Coffin | Renner

December 20, 2019

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 Central Texas Service Area ("CTSA"), the Gulf Coast Service Area ("GCSA") and the City of Beaumont. In addition to the rate and tariff changes contained in the Statement of Intent, TGS is also requesting consolidation of the CTSA, GCSA and City of Beaumont into a single Central-Gulf Service Area ("CGSA"). For that reason, the filing contains three sets of schedules that reflect: (1) combined CGSA data (2) stand-alone CTSA data; and (3) stand-alone GCSA data. The combined CGSA data provides the basis for the Company's requested rates. The Company is also providing a version of the CGSA 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 February 6, 2020, which is 48 days from the date of this filing. No action on the part of the CTSA Cities, GCSA Cities or City of Beaumont 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 CTSA and GCSA in which it is requesting the same rate and tariff changes that are contained in the city-level filing for the incorporated areas of the CTSA, GCSA and the City of Beaumont. As part of the Commission filing, the Company is also requesting a finding, to the extent necessary, that the acquisition of ONEOK Transmission Company and its assets that occurred June 30, 2019, is in the public interest. Additionally, TGS is requesting that the Commission approve new depreciation rates. 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 CENTRAL TEXAS SERVICE AREA, GULF COAST SERVICE AREA AND CITY OF BEAUMONT

To All Cities Within Texas Gas Service Company's Central Texas and Gulf Coast Service Areas and the City of Beaumont:

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 Gas Services Department of the Railroad Commission of Texas ("Commission"), to change gas utility rates within the City of Beaumont and the incorporated areas of the Central Texas Service Area ("CTSA"), which includes Austin, Bee Cave, Cedar Park, Cuero, Dripping Springs, Gonzales, Kyle, Lakeway, Lockhart, Luling, Rollingwood, Shiner, Sunset Valley, Nixon, West Lake Hills and Yoakum and the Gulf Coast Service Area ("GCSA"), which includes Bayou Vista, Galveston, Groves, Jamaica Beach, Nederland, Port Arthur and Port Neches. As part of this rate filing, the Company also proposes to consolidate the CTSA, the GCSA, and the City of Beaumont into a new service area called the Central-Gulf Service Area ("CGSA"). Consistent with this request to consolidate service areas, the Company's proposed rates were developed based on the cost of providing service to the entire proposed CGSA. Contemporaneously with this filing, TGS is also filing a Statement of Intent to Change Rates for the unincorporated areas of the CTSA and GCSA with the Commission.

The Company requests that the proposed rate schedules and tariffs for the proposed new CGSA, attached to this Statement of Intent as **Exhibit A** and incorporated herein by reference, become effective on February 6, 2020, which is 48 days from the date of this filing.[1] 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:

[1] TGS is proposing an effective date past the statutory 35-day effective date period to accommodate holiday-related closures.

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 CGSA. The new rates will affect all customers in the proposed CGSA, which include residential, commercial, commercial transportation, industrial, industrial transportation, public authority, public authority transportation, public school space heating, public school space heating transportation, compressed natural gas, compressed natural gas transportation, and electrical cogeneration transportation customers.

For the 12-month period ended June 30, 2019, updated for known and measurable adjustments through September 30, 2019, the Company's overall, combined revenue requirement for the proposed CGSA on a system-wide basis totaled approximately $126 million, as adjusted.[2] The total revenue TGS received during the test year from customers within proposed CGSA was approximately $109 million, leaving a revenue deficiency on a combined basis of approximately $17 million.

If approved, the requested rates will increase TGS's revenues in the proposed CGSA by $17 million, which is an increase of 9.43% including gas costs, or 15.64% excluding gas costs. Because the proposed changes will increase TGS's total aggregate revenues within the proposed CGSA by more than 2.5%, the proposed rate increases constitute a "major change" in rates as that term is defined by Texas Utilities Code § 104.101. Additionally, the proposed rates will not exceed 115% of the average of all rates for similar services of all municipalities served by the Company within the same county.

As part of this rate filing, the Company is also requesting: (1) Commission approval of new depreciation rates for Direct and Division distribution and general plant within the proposed CGSA; (2) a prudence determination for capital investment made in the proposed CGSA through December 31, 2019; (3) a finding from the Commission that ONE Gas' acquisition of ONEOK

[2] TGS included September 30, 2019 Construction Work in Progress ("CWIP") balances as an adjustment to construction completed not classified ("CCNC"). TGS will true-up net plant after December 31, 2019 to exclude any plant that is not used and useful at that time and will provide updated plant in service amounts, CCNC and accumulated reserves balances, along with related updated accumulated deferred income taxes and revenue growth, by February 14, 2020.

Transmission Company ("OTC") and its assets is consistent with the public interest under Texas Utilities Code § 102.051; (4) 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; (5) approval of the form of notice pursuant to the proposed Rate Schedule PIT; and (6) 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 CGSA rate schedules and tariffs would be applicable to the entire CGSA, should consolidation as requested be approved. Implementation of new CGSA tariffs necessarily entails withdrawal of the Company's existing City of Beaumont tariffs and CTSA and GCSA incorporated and environs tariffs for which the Company is proposing changes. The Company is proposing: (1) a new residential A/B rate design that will provide options for customers based on their usage patterns; (2) Rate Schedules 70 and 7Z for unmetered gas street lights; (3) Rate Schedule EDIT-Rider to flow excess deferred income taxes back to customers; (4) Rate Schedule HARV-Rider to recover approved Hurricane Harvey; (5) Rate Schedules PIT and PIT-Rider to recover pipeline integrity testing costs; (6) and Rate Schedule NER to allow TGS to defer and later seek recovery of future extraordinary expenses associated with TGS's efforts to restore service after storms and other natural disasters or events, less any insurance reimbursement. 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 CGSA.

III. CONSOLIDATION OF SERVICE AREAS

In developing the requested rates, the Company is proposing to consolidate the CTSA, GCSA and the City of Beaumont into a new, combined service area known as the CGSA.[3] The CTSA is currently comprised of the incorporated areas of Austin, Bee Cave, Cedar Park, Cuero, Dripping Springs, Gonzales, Kyle, Lakeway, Lockhart, Luling, Rollingwood, Shiner, Sunset Valley, Nixon, West Lake Hills and Yoakum, Texas and their associated environs, including the environs of Buda, Texas. The GCSA is currently comprised of the incorporated areas of Bayou Vista, Galveston, Groves, Jamaica Beach, Nederland, Port Arthur and Port Neches, Texas and their associated environs. While the Company's past practice has been to develop separate rates based on the individual costs of service of the CTSA and GCSA, the Company seeks in this proceeding, consistent with prior Commission decisions for TGS, to consolidate these two service areas as well as the City of Beaumont and use a system-wide cost of service for the entire proposed CGSA to realize efficiencies from the centralization of its existing operations in the separate service areas. The Company's proposed rates for customers in the CTSA, GCSA, and City of Beaumont are based on the system-wide cost of providing service to the proposed CGSA.

If the Company's consolidation request is not approved, the Company requests approval of new base rates for the CTSA and GCSA based on the separate cost of service schedules for each service area that are included with the Statement of Intent filing. Costs for the City of Beaumont are reflected in the GCSA schedules.

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

[3] If consolidation and creation of the CGSA is not approved, TGS requests, at a minimum, that the City of Beaumont be consolidated into the GCSA.

- 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 CGSA as set forth in this Statement of Intent and Rate Filing Package is based on the 12-month period ended June 30, 2019, updated for known and measurable changes through September 30, 2019.[4]

C. Effective Date

The Company requests that the proposed rates be effective for meters read on and after February 6, 2020.

D. Class and Number of Customers Affected

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

Customer Class	CTSA Customers Incorporated/Environs	GCSA Customers Incorporated/Environs
Residential	229,420/22,251	41,183/1,142
Commercial	11,658/650	1,782/28
Industrial	21/No Customers	No Customers
Public Authority	519/47	261/4
Public School Space Heating	4/1	No Customers
Compressed Natural Gas	3/No Customers	No Customers
Commercial Transportation	327/9	30/No Customers
Public Authority Transportation	384/6	No Customers
Public School Space Heating Transportation	80/2	No Customers
Industrial Transportation	32/1	4/No Customers
Electrical Cogeneration Transportation	1/No Customers	No Customers
Compressed Natural Gas Transportation	3/1	No Customers

The City of Beaumont has one residential and one commercial customer.

[4] TGS included September 30, 2019 CWIP balances as an adjustment to CCNC. TGS will true-up net plant after December 31, 2019 to exclude any plant that is not used and useful at that time and will provide updated plant in service amounts, CCNC and accumulated reserves balances, along with related updated accumulated deferred income taxes and revenue growth, by February 14, 2020.

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 following rate schedules and tariffs for the proposed CGSA, which are attached to this Statement of Intent as **Exhibit A** and incorporated herein by reference. One change that applies to all proposed CGSA tariffs is a revision to the "Territory" sections to include all CTSA Cities, GCSA cities and the City of Beaumont in the incorporated tariffs and to include CTSA environs, CTSA environs and environs of the City of Beaumont in the environs tariffs. In addition, TGS proposes the following specific changes:

1. *Proposed Rate Schedules for General Sales Customers*: For residential, commercial, industrial, public authority and public schools general sales customers, the Company proposes TGS proposes to add references to Rate Schedule EDIT-Rider, Rate Schedule HARV-Rider, and Rate Schedule NER-Rider, under "Other Adjustments."

   a. *Rate Schedules 10 and 1Z:* For Residential gas sales service, the Company proposes to add residential builders to the "Applicability" sections; and add a new residential A/B rate design that will provide options for customers based on their usage patterns.

   b. *Rate Schedules 20 and 2Z:* For Commercial gas sales service, the Company proposes to include all CTSA Cities, GCSA Cities and the City of Beaumont in the "Territory" section in the incorporated tariffs and to include all CTSA environs, GCSA environs and Beaumont, Texas environs in the "Territory" section in the environs tariffs; add references to Rate Schedule EDIT-Rider, Rate Schedule HARV-Rider, and Rate Schedule NER-Rider, under "Other Adjustments;" and remove unmetered service language in the "Conditions" section of GCSA and City of Beaumont because this provision is contained in the Company's proposed Rate Schedules 70 and 7Z.

   c. *Rate Schedules 30 and 3Z:* For Industrial gas sales service, the Company proposes to include all CTSA Cities, GCSA Cities and the City of Beaumont in the "Territory" section in the incorporated tariffs and to include all CTSA environs, GCSA environs and Beaumont, Texas environs in the "Territory" section in the environs tariffs; add references to Rate Schedule EDIT-Rider, Rate Schedule HARV-Rider, and Rate Schedule NER-Rider, under "Other Adjustments;" and remove curtailment language in the "Conditions" sections because these provisions are contained in the curtailment plan on file with the Commission.

d. *Rate Schedules 40 and 4Z:* For Public Authority gas sales service, the Company proposes to include all CTSA Cities, GCSA Cities and the City of Beaumont in the "Territory" section in the incorporated tariffs and to include all CTSA environs, GCSA environs and Beaumont, Texas environs in the "Territory" section in the environs tariffs; add references to Rate Schedule EDIT-Rider, Rate Schedule HARV-Rider, and Rate Schedule NER-Rider, under "Other Adjustments;" and remove unmetered service language in the "Conditions" section of GCSA and City of Beaumont Rate Schedules 40 and 4Z because this provision is contained in the Company's proposed Rate Schedules 70 and 7Z.

e. *Rate Schedules 48 and 4H*: For Public School Space Heating gas sales service, the Company proposes to include all CTSA Cities, GCSA Cities and the City of Beaumont in the "Territory" section in the incorporated tariffs and to include all CTSA environs, GCSA environs and Beaumont, Texas environs in the "Territory" section in the environs tariffs and add references to Rate Schedule EDIT-Rider, Rate Schedule HARV-Rider, and Rate Schedule NER-Rider, under "Other Adjustments."

f. *Rate Schedules T-1, T-1-ENV and T-TERMS*: For Transportation service, the Company proposes to include all CTSA Cities, GCSA Cities and the City of Beaumont in the "Territory" section in the incorporated tariffs and to include all CTSA environs, GCSA environs and Beaumont, Texas environs in the "Territory" section in the environs tariffs and add references to Rate Schedule EDIT-Rider, Rate Schedule HARV-Rider, and Rate Schedule NER-Rider, under "Other Adjustments." For Rate Schedule T-TERMS the Company proposes to include definitions for commercial, electrical cogeneration, and industrial service under "Definitions" to provide clarity and match the terminology in the proposed CGSA Rules of Service.

g. *Rate Schedules C-1 and C-1-ENV:* For Cogeneration service, the Company proposes to include all CTSA Cities, GCSA Cities and the City of Beaumont in the "Territory" section in the incorporated tariffs and to include all CTSA environs, GCSA environs and Beaumont, Texas environs in the "Territory" section in the environs tariffs and add references to Rate Schedule EDIT-Rider, Rate Schedule HARV-Rider, and Rate Schedule NER-Rider, under "Other Adjustments."

h. *Rate Schedules CNG-1 and CNG-1-ENV:* For Compressed Natural Gas service, the Company proposes to include all CTSA Cities, GCSA Cities and the City of Beaumont in the "Territory" section in the incorporated tariffs and to include all CTSA environs, GCSA environs and Beaumont, Texas environs in the "Territory" section in the environs tariffs; add references to Rate Schedule EDIT-Rider, Rate Schedule HARV-Rider, and Rate Schedule NER-Rider, under "Other Adjustments;" and clarify the reference and availability of the Average Payment Plan/Average Bill Calculation Plan (ABC/APP Plan) under "Conditions."

i. *Rate Schedules 1-INC and I-ENV*: For the Cost of Gas clauses, the Company proposes to include all CTSA Cities, GCSA Cities and the City of Beaumont in the "Territory" section in the incorporated tariffs and to include all CTSA environs, GCSA environs and Beaumont, Texas environs in the "Territory" section in the environs tariffs; add clarifying language to section B.7 regarding lost and unaccounted for gas to match section B.5; add clarifying language to section B.8 in the incorporated tariff and revise section B.3 in the environs tariff to make consistent with; approved cost of gas clauses in GUD Nos. 10656, 10739, and 10766; revise sections B.3, B.5, B.7, and H.4 in the incorporated cost of gas clause to include the use of financial instruments; and revise sections B, D, E, G, and H to make the language consistent with the cost of gas clauses in the existing CTSA.

j. *Rate Schedule WNA*: Provides a mechanism whereby incorporated 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. Buchanan. Revisions have been made to Rate Schedule WNA to: add the incorporated and environs GCSA and Beaumont customers to the applicability section; and reflect updated weather factors for each class consistent with Ms. Buchanan's weather normalization calculation in this case.

k. *Rate Schedule EDIT-Rider:* Provides a mechanism for the flow back to customers of the annual amortization of EDIT, via a one-time bill credit.

l. *Rate Schedules PIT and PIT-Rider*: Provides a mechanism 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.

m. *Rate Schedule HARV-Rider:* Provides a mechanism for the recovery of reasonable and necessary expenses TGS incurred to restore service as a direct result of Hurricane Harvey.

n. *Rate Schedules NER and NER-Rider:* Provides a mechanism to defer and seek recovery of operations and maintenance ("O&M") expenses resulting from natural events.

o. *Rate Schedules 70 and 7Z:* Provides a mechanism to provide unmetered service to customers using natural gas for gas lighting only.

p. *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 CTSA cities, GCSA cities, City of Beaumont and the Commission.

q. *Rate Schedule PSF*: Provides a mechanism to recover the annual fee to support the pipeline safety functions of the Commission.

r. *Rules of Service*: For the Rules of Service, the Company proposes

1. Including the incorporated and environs areas of the CTSA, GCSA and Beaumont in § 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 and 10766, 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 CGSA tariffs;
3. Revisions to § 4.5 to better reflect the current course of action customers can take to obtain copies of their tariffs and rate schedules;
4. Revisions to § 4.6 to clarify how and when the Company provides general information to new customers;
5. Revisions to § 7.1 to make advance contribution in aid of construction from an applicant of new service discretionary;
6. Revision to § 7.4 and § 15.8 to clarify that there is no charge to the customer when Company personnel inspect or perform tests on new installations or appliances prior to initiation of service;
7. Addition of § 10.6 which specifies that when a franchise agreement may be in conflict with the terms and conditions of Section § 10, Security Deposits, the franchise agreement terms apply;
8. Revisions to the table in § 11.1 to include the City of Beaumont and the Gulf Coast Cities' atmospheric and standard serving pressures;
9. Revision to § 12.2 to establish consistency across the Rules of Service regarding a customer's obligations to grant premise and meter access to Company personnel;
10. Revisions to § 13.7 to clarify payment options administered by contracted vendors;
11. Addition of § 13.8, Deferred Payment Plans, to provide terms and conditions of deferred payment plans that may be offered by the Company to customers consistent with Commission Rule § 7.45(2)(D);
12. Addition of § 17.3 which relates to the suspension of gas utility service disconnection during an extreme weather emergency consistent with Commission Rule § 7.46, and the Company proposes to withdraw the existing CTSA, GCSA and Beaumont environs Rules of Service addendum;
13. Revisions to § 20 to update the language to better reflect current plan descriptions; and

14. Revisions to § 21, Fees and Deposits, to establish greater consistency for service fees and deposits among the Company's service areas.

The Company proposes to withdraw the existing CTSA, GCSA, and Beaumont environs Rules of Service addendum waiving the deposit requirement for victims of family violence because the provision is now included in § 5.5 of the proposed Rules of Service.

F. Effect of Proposed Rate Changes

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

	Incorporated and Unincorporated/Environs Current Rates					
Customer Class	**CTSA Incorporated Rates**	**CTSA Environs Rates**	**GCSA Incorporated Rates**	**GCSA Environs Rates**	**City of Beaumont Rates**	**Proposed CGSA Rates**
Residential (No. of Customers Affected)	229,420	22,251	41,183	1,142	1	
Customer Charge	$18.81	$18.81	$12.42	$14.17	$12.10	$14.00 (Option A) $27.58 (Option B)
Volumetric Charge (per Ccf)	$0.12064	$0.12064	$0.45616	$0.40680	$0.45616	$0.55702 (Option A) $0.10435 (Option B)
Commercial (No. of Customers Affected)	11,658	650	1,782	28	1	
Customer Charge	$53.33	$53.33	$51.11	$59.92	$49.49	$53.33
Volumetric Charge (per Ccf)	$0.11614	$0.11614	$0.22140 (First 250 Ccf) ------- $0.19380 (All Over 250 Ccf)	$0.20185 (First 250 Ccf) ------- $0.17425 (All Over 250 Ccf)	$0.22140 (First 250 Ccf) ------- $0.19380 (All Over 250 Ccf)	$0.12678
Commercial Transportation (No. of Customers Affected)	327	9	30	No Customers	No Customers	
Customer Charge	$265.33	$265.33	$297.11	$305.92	$295.49	$265.33

Customer Class	CTSA Incorporated Rates	CTSA Environs Rates	GCSA Incorporated Rates	GCSA Environs Rates	City of Beaumont Rates	Proposed CGSA Rates
Volumetric Charge (per Ccf)	$0.11614	$0.11614	$0.22140 (First 250 Ccf) ------- $0.19380 (All Over 250 Ccf)	$0.20185 (First 250 Ccf) ------- $0.17425 (All Over 250 Ccf)	$0.22140 (First 250 Ccf) ------- $0.19380 (All Over 250 Ccf)	$0.12678
Industrial (No. of Customers Affected)	21	No Customers	No Customers	No Customers	No Customers	
Customer Charge	$320.96	$320.96	$153.41	$242.79	$153.41	$320.96
Volumetric Charge (per Ccf)	$0.10273	$0.10273	$0.40060 (First 250 Ccf) ------- $0.37480 (All Over 250 Ccf)	$0.37808 (First 250 Ccf) ------- $0.35228 (All Over 250 Ccf)	$0.40060 (First 250 Ccf) ------- $0.37480 (All Over 250 Ccf)	$0.12703
Industrial Transportation (No. of Customers Affected)	32	1	4	No Customers	No Customers	
Customer Charge	$520.96	$520.96	$249.73	$432.79	$217.42	$520.96
Volumetric Charge (per Ccf)	$0.10273	$0.10273	$0.40060 (First 250 Ccf) ------- $0.37480 (All Over 250 Ccf)	$0.37808 (First 250 Ccf) ------- $0.35228 (All Over 250 Ccf)	$0.40060 (First 250 Ccf) ------- $0.37480 (All Over 250 Ccf)	$0.12703
Public Authority (No. of Customers Affected)	519	47	261	4	No Customers	
Customer Charge	$81.70	$81.70	$106.10	$117.78	$103.95	$81.70
Volumetric Charge (per Ccf)	$0.11541	$0.11541	$0.15672 (First 250 Ccf) ------- $0.13092 (All Over 250 Ccf)	$0.13587 (First 250 Ccf) ------- $0.11007 (All Over 250 Ccf)	$0.15672 (First 250 Ccf) ------- $0.13092 (All Over 250 Ccf)	$0.12551
Public Authority Transportation (No. of Customers Affected)	384	6	No Customers	No Customers	No Customers	
Customer Charge	$104.70	$104.70	$302.36	$307.78	$302.36	$104.70

Customer Class	CTSA Incorporated Rates	CTSA Environs Rates	GCSA Incorporated Rates	GCSA Environs Rates	City of Beaumont Rates	Proposed CGSA Rates
Volumetric Charge (per Ccf)	$0.11541	$0.11541	$0.15672 (First 250 Ccf) ------- $0.13092 (All Over 250 Ccf)	$0.13587 (First 250 Ccf) ------- $0.11007 (All Over 250 Ccf)	$0.15672 (First 250 Ccf) ------- $0.13092 (All Over 250 Ccf)	$0.12551
Electrical Cogeneration (No. of Customers Affected)	No Customers	No Customers	No Customers	No Customers	No Customers	
Customer Charge	$104.70	$104.70	NA	NA	NA	$104.70
Volumetric Charge (per Ccf)	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)	NA	NA	NA	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)
Electrical Cogeneration Transportation (No. of Customers Affected)	1	No Customers	No Customers	No Customers	No Customers	
Customer Charge	$104.70	$104.70	NA	NA	NA	$104.70
Volumetric Charge (per Ccf)	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)	NA	NA	NA	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)
Public School Space Heating (No. of Customers Affected)	4	1	No Customers	No Customers	No Customers	
Customer Charge	$134.70	$134.70	NA	NA	NA	$134.70
Volumetric Charge (per Ccf)	$0.10012	$0.10012	NA	NA	NA	$0.10012

Customer Class	CTSA Incorporated Rates	CTSA Environs Rates	GCSA Incorporated Rates	GCSA Environs Rates	City of Beaumont Rates	Proposed CGSA Rates
Public School Space Heating Transportation (No. of Customers Affected)	80	2	No Customers	No Customers	No Customers	
Customer Charge	$234.70	$234.70	NA	NA	NA	$234.70
Volumetric Charge All Ccf	$0.10012	$0.10012	NA	NA	NA	$0.10012
Compressed Natural Gas (No. of Customers Affected)	3	No Customers	No Customers	No Customers	No Customers	
Customer Charge	$192.63	$192.63	NA	NA	NA	$192.63
Volumetric Charge (per Ccf)	$0.06684	$0.06684	NA	NA	NA	$0.06684
Compressed Natural Gas Transportation (No. of Customers Affected)	3	1	No Customers	No Customers	No Customers	
Customer Charge	$217.63	$217.63	NA	NA	NA	$217.63
Volumetric Charge (per Ccf)	$0.06684	$0.06684	NA	NA	NA	$0.06684

Exhibit C shows the average bill impact by customer class.

G. Witness Testimony

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

- *G. David Scalf* is Vice-President of Rates and Regulatory for ONE Gas. Mr. Scalf introduces TGS's Statement of Intent filing and the witnesses, provides an overview of ONE Gas and the Company's request to consolidate its existing CTSA, GCSA and the City of Beaumont into a new consolidated service area, the CGSA, and addresses two adjustments in Schedule G from a management perspective: (1) incentive compensation and (2) meal and hotel costs.

- *Shantel Norman* is Vice-President of Operations for TGS. Ms. Norman provides an overview of operations within the proposed CGSA; supports the proposed consolidation to create the CGSA; addresses the reasonableness and necessity of capital investment and

O&M expenses; addresses ONE Gas' recent acquisition of OTC and the planned integration of the associated pipeline into TGS's system; and addresses the Company's Pipeline Integrity Testing Program.

- *Stacey L. McTaggart* is the Rates and Regulatory Director for TGS. Ms. McTaggart addresses the proposed consolidation of the existing CTSA, GCSA and City of Beaumont into the new CGSA; the request for a finding that ONE Gas' acquisition of the former OTC assets in June 2019, now held by ONE Gas Pipeline Company ("OPC"), is consistent with the public interest; the transfer of the OPC assets into TGS's existing system; the Company's compliance with certain regulatory and statutory requirements; affiliate cost recovery issues related to Utility Insurance Company ("UIC") and OPC; the Company's compliance with the Accounting Order issued by the Commission in GUD No. 10695 related to the federal Tax Cut and Jobs Act of 2017; the Company's proposed EDIT Rider to return excess deferred income taxes to customers; the proposed treatment of cloud-based computing costs in future filings; TGS's recovery of costs associated with the Company's response to Hurricane Harvey; the Company's recovery of pipeline integrity testing costs; the proposed Natural Events Response Rider; and the Company's recovery of rate case expenses.

- *Janet L. Buchanan* is the Rates and Regulatory Director for Kansas Gas Service. Ms. Buchanan supports TGS's revenue adjustments.

- *Gracie Guerra* is a Rates Analyst for TGS and provides an overview of the cost of service and overall revenue requirement calculation and supports TGS's Direct rate base.

- *Mindy R. Edwards* is a Rates Analyst for ONE Gas and supports certain TGS Division and Corporate capital investment that is included in the CGSA revenue requirement as well as Corporate depreciation and amortization expense.

- *Marie J. Michels* is a Manager of Rates and Regulatory Analysis for TGS. Ms. Michels supports Direct expense adjustments including an adjustment for O&M expenses related to the operation of the OPC pipeline, among others adjustments.

- *Anthony Brown* is a Rates Specialist for TGS. Mr. Brown supports the cost allocation methodology used to determine TGS's share of allocated costs and certain Corporate expense adjustments.

- *Allison N. Edwards* is a Manager of Rates and Regulatory Analysis for ONE Gas. Ms. Edwards supports adjustments related to meal and hotel costs.

- *Stacey R. Borgstadt* is a Manager of Rates and Regulatory Analysis for ONE Gas. Ms. Borgstadt explains Direct, TGS Division and Corporate expense adjustments related to payroll and incentive compensation.

- *Timothy S. Lyons* is a Partner with the firm ScottMadden, Inc. Mr. Lyons sponsors the Company's cash working capital study and proposed cash working capital amounts.

- *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.

- *Cyndi King* is Director of Treasury and Finance for ONE Gas. Ms. King provides testimony supporting the recovery of a return on the Company's prepaid pension asset.

- *Mark W. Smith* is a Vice-President and the Treasurer for ONE Gas. Mr. Smith describes the insurance services that ONE Gas affiliate, UIC, provided to TGS during the test year.

- *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 Excess Deferred Income Tax or EDIT.

- *Janet M. Simpson* is an accountant and vice-president at Dively Energy Services. Ms. Simpson presents the calculations for the Company's Accumulated Deferred Income Tax.

- *Ronald E. White* is an engineer and President of Foster Associates Consultants, LLC. Dr. White sponsors and describes a study of the depreciation rates for the Company's plant located in the proposed CGSA, as well as 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 addresses and supports the Company's requested return on equity, cost of debt, capital structure, and overall return on invested capital (weighted average cost of capital).

- *Crystal D. Drumm* is a Rates Specialist for ONE Gas. Ms. Drumm describes and supports the Company's proposed interclass cost allocations and rate design.

- *Paul H. Raab* is an Economic Consultant with energytools, llc and describes and supports TGS's proposed rate design, including options that allow for customer choice.

- *Christy M. Bell* is a Rates Analyst for TGS. Ms. Bell describes the proposed CGSA rate schedules and tariffs as well as rate schedules and tariffs currently in effect for the CTSA, GCSA, and the City of Beaumont.

V. REQUEST FOR PUBLIC INTEREST FINDING

TGS is requesting a finding from the Commission that ONE Gas' acquisition of OTC and its assets is consistent with the public interest under Texas Utilities Code § 102.051.

VI. 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.

VII. 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 CGSA 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.

VIII. COMPANY REPRESENTATIVES FOR NOTIFICATION

TGS's authorized representatives are:

Stephanie G. Houle
Teresa Serna
Stacey L. McTaggart
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
Teresa.Serna@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.

IX. 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.

X. CONCLUSION

TGS requests that: (1) rates are approved for the proposed CGSA consistent with those proposed herein, to become effective for meters read on and after February 6, 2020; (2) consolidation of the existing CTSA, GCSA and City of Beaumont is approved to create the CGSA; (3) the Commission approve new depreciation rates for Direct and Division distribution and general plant; (4) capital investment in the proposed CGSA made through December 31, 2019 is deemed prudent; (5) the Commission find the acquisition of ONEOK Transmission Company and its assets is consistent with the public interest; (6) 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; (7) the form of notice pursuant to proposed Rate Schedule PIT is approved; (8) all reasonable rate case expenses incurred in connection with this Statement of Intent filing are authorized for recovery by the Company; and (9) for such further relief to which the Company may be entitled.

Respectfully submitted,

By: Kate Norman

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1301 S. Mopac, Suite 400
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glenn.adkins@crtxlaw.com

ATTORNEYS FOR TEXAS GAS SERVICE COMPANY

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE 10**

RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a 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. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

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

COST OF SERVICE RATE CHOICES

During each monthly billing period:

For Rate A

A customer charge per meter per month of	$14.00 plus
All Ccf per monthly billing period @	$0.55702 per Ccf

For Rate B

A customer charge per meter per month of	$27.58 plus
All Ccf per monthly billing period @	$0.10435 per Ccf

CUSTOMER CHOICE RATE PLACEMENT

Each customer's individual rate schedule will be determined 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 choice for the new account.

If the customer's service location's annual normalized volume is less than 360 Ccf, then the customer's account will be placed on Rate A.

If the customer's service location's annual normalized volume is 360 Ccf or greater, then the customer's account will be placed on Rate B.

A customer may switch rate choices at any time during the year provided that the customer agrees to remain on the alternative rate for a period of no less than twelve (12) months after switching options. Changes will be effective with the Customer's next scheduled bill.

Supersedes Rate Schedule Dated	Meters Read On and After
June 3, 2019 (Austin Only)	TBD
June 14, 2019 (All Other Inc. Areas, Central Texas Service Area)	
July 29, 2019 (Gulf Coast Service Area)	
May 22, 2019 (City of Beaumont)	

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE 10**

RESIDENTIAL SERVICE RATE
(Continued)

OTHER ADJUSTMENTS

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

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

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

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

CONDITIONS

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

Supersedes Rate Schedule Dated
June 3, 2019 (Austin Only)
June 14, 2019 (All Other Inc. Areas, Central Texas Service Area)
July 29, 2019 (Gulf Coast Service Area)
May 22, 2019 (City of Beaumont)

Meters Read On and After
TBD

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE 20**

COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to all commercial customers and to customers not otherwise specifically provided for under any other rate schedule. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	\$53.33 plus
All Ccf per monthly billing period @	\$0.12678 per Ccf

OTHER ADJUSTMENTS

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

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

Supersedes Rate Schedule Dated	Meters Read On and After
June 3, 2019 (Austin Only) June 14, 2019 (All Other Inc. Areas, Central Texas Service Area) July 29, 2019 (Gulf Coast Service Area) May 22, 2019 (City of Beaumont)	TBD

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE 20**

COMMERCIAL SERVICE RATE
(Continued)

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

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

CONDITIONS

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

Supersedes Rate Schedule Dated	Meters Read On and After
June 3, 2019 (Austin Only)	TBD
June 14, 2019 (All Other Inc. Areas, Central Texas Service Area)	
July 29, 2019 (Gulf Coast Service Area)	
May 22, 2019 (City of Beaumont)	

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

INDUSTRIAL SERVICE RATE

APPLICABILITY

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

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

TERRITORY

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$320.96 plus
All Ccf per monthly billing period @	$0.12703 per Ccf

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

Supersedes Rate Schedule Dated	Meters Read On and After
June 3, 2019 (Austin Only)	TBD
June 14, 2019 (All Other Inc. Areas, Central Texas Service Area)	
July 29, 2019 (Gulf Coast Service Area)	
May 22, 2019 (City of Beaumont)	

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

INDUSTRIAL SERVICE RATE
(Continued)

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

CONDITIONS

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

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

PUBLIC AUTHORITY SERVICE RATE

APPLICABILITY

Applicable to any qualifying public authority, public and parochial schools and colleges, and to all facilities operated by Governmental agencies not specifically provided for in other rate schedules or special contracts. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$81.70 plus
All Ccf per monthly billing period @	$0.12551 per Ccf

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

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

Supersedes Rate Schedule Dated	Meters Read On and After
June 3, 2019 (Austin Only) June 14, 2019 (All Other Inc. Areas, Central Texas Service Area) July 29, 2019 (Gulf Coast Service Area) May 22, 2019 (City of Beaumont)	TBD

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

PUBLIC AUTHORITY SERVICE RATE
(Continued)

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

CONDITIONS

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

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE 48**

PUBLIC SCHOOLS SPACE HEATING SERVICE RATE

APPLICABILITY

Applicable to public schools for space heating purposes. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$134.70 plus
All Ccf per monthly billing period @	$0.10012 per Ccf

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

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

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

Supersedes Rate Schedule Dated	Meters Read On and After
June 3, 2019 (Austin Only)	TBD
June 14, 2019 (All Other Inc. Areas, Central Texas Service Area)	

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE 48**

PUBLIC SCHOOLS SPACE HEATING SERVICE RATE
(Continued)

CONDITIONS

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

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf 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 walk ways. The Company, in its sole discretion, shall determine if Customer's lighting equipment qualifies for this tariff and shall contract with Customer for the appropriate monthly charge based upon Customer's complete installation of gas lighting equipment. Gas service under this rate schedule is available only with the Company as the sole supplier of gas for Customer and is not available for resale to others or for standby or supplemental service. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

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

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	$ 0.10435 per Ccf
Commercial	$ 0.12678 per Ccf
Industrial	$ 0.12703 per Ccf
Public Authority	$ 0.12551 per Ccf

OTHER ADJUSTMENTS

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

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

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

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

RATE SCHEDULE NO. C-1
Page 1 of 2

ELECTRICAL COGENERATION RATE

APPLICABILITY

Service under this rate schedule is available to any customers of Texas Gas Service Company, a Division of ONE Gas, Inc., (the "Company") who use natural gas for the purpose of cogeneration or the use of fuel cell technology. 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

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of $ 104.70 plus

For the First	5,000 Ccf/Month	$ 0.07720 per Ccf
For the Next	35,000 Ccf/Month	$ 0.06850 per Ccf
For the Next	60,000 Ccf/Month	$ 0.05524 per Ccf
All Over	100,000 Ccf/Month	$ 0.04016 per Ccf

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

ELECTRICAL COGENERATION RATE
(Continued)

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

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

CONDITIONS

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

This rate will not be available for standby use.

The curtailment priority of any customer served under this rate schedule shall be the same as the curtailment priority which would pertain if gas were used directly to provide energy for uses as defined and listed in the Company's curtailment plan.

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

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

**RATE SCHEDULE CNG-1
Page 1 of 2**

COMPRESSED NATURAL GAS SERVICE RATE

APPLICABILITY

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

TERRITORY

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$192.63 plus
All Ccf per monthly billing period @	$0.06684 per Ccf

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

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

Supersedes Rate Schedule Dated
June 3, 2019 (Austin Only)
June 14, 2019 (All Other Inc. Areas, Central Texas Service Area)

Meters Read On and After
TBD

COMPRESSED NATURAL GAS SERVICE RATE
(Continued)

CONDITIONS

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

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

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

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

Compressor station subject to inspection by Company engineers.

COST OF GAS CLAUSE

A. APPLICABILITY

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

B. DEFINITIONS

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

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

3. Cost of Purchased Gas - The estimated cost for gas purchased by the Company from its suppliers or the estimated weighted average cost for gas purchased by the Company from all sources where applicable. Such cost shall include not only the purchase cost of natural gas, but shall also include all reasonable costs for services such as gathering, treating, processing, transportation, capacity and/or supply reservation, storage, balancing including penalties, and swing services necessary for the movement of gas to the Company's city gate delivery points. The cost of purchased gas may also include costs related to the purchase and transportation of Renewable Natural Gas (RNG). Renewable Natural Gas is the term used to describe pipeline-quality biomethane produced from biomass. The cost of purchased gas shall also include 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.

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

5. Reconciliation Audit - An annual review of the Company's books and records for each 12-month period ending with the production month of June to determine the amount of over or under collection occurring during such 12-month period. The audit shall determine: (a) the total amount paid for gas purchased by the Company (per Section B(3) above) to provide service to its general service 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 and taxes paid by the Company on those revenues; (c) the total amount of refunds made to 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

COST OF GAS CLAUSE
(Continued)

for imbalances under the transportation rate schedule(s) net of fees and applicable taxes; (e) the total amount of Uncollectible Cost of Gas during the period; and (f) an adjustment, if necessary, to remove lost and unaccounted for gas costs during the period for volumes in excess of 5 percent of purchases.

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

7. Reconciliation Account - The account maintained by the Company to assure that over time it will neither over nor under collect revenues as a result of the operation of the Cost of Gas Clause. Entries shall be made monthly to reflect: (a) the total amounts paid to the Company's supplier(s) for gas applicable to general service 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; (c) refunds, payments, or charges provided for herein or as approved by the regulatory authority; (d) amounts accrued pursuant to the treatment of imbalances under any transportation rate schedule(s), (e) total amount of Uncollectible Cost of Gas during the period; and (f) an adjustment, if necessary, for lost and unaccounted for gas during the period in excess of 5 percent of purchases.

8. 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 general service rate schedules, the Company shall bill each general service 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 general service sales volumes, adjusted for the effects of weather, growth, and conservation for the period beginning with the October billing cycle through the June billing cycle preceding the filing of the Reconciliation Audit. The Reconciliation Component so determined to collect any revenue shortfall or to return any excess revenue shall be applied, subject to refund, for a 9 month period beginning with the October billing cycle and continuing through the next June billing cycle at which time it will terminate.

Supersedes Rate Schedule Dated
1-INC dated September 8, 2017 (Cities of Austin, Bee Cave, Cedar Park, Cuero, Dripping Springs, Gonzales, Kyle, Lakeway, Lockhart, Luling, Nixon, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, TX)
1-INC (GALV) dated May 9, 2016 (Cities of Bayou Vista, Galveston, and Jamaica Beach, TX)
1-INC (SJC) dated May 9, 2016 (Cities of Groves, Nederland, Port Arthur, and Port Neches, TX)
1-INC dated May 22, 2019 (City of Beaumont)

Meters Read On and After
TBD

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

Rate Schedule 1-INC
Page 3 of 5

COST OF GAS CLAUSE
(Continued)

E. INTEREST ON FUNDS

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

F. SURCHARGE OR REFUND PROCEDURES

In the event that the rates and charges of the Company's supplier are retroactively reduced and a refund of any previous payments is made to the Company, the Company shall make a similar refund to its general service customers. Similarly, the Company may surcharge its general service 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. 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 Reconciliation Component; (e) the revenue associated fees and taxes to be applied to revenues generated by the Cost of Gas; (f) the Cost of Gas calculation, including gains and losses from hedging activities for the month; and (g) the beginning and ending date of the billing period. The statement shall include all data necessary for the Regulatory Authority to review and verify the calculations of the Cost of Gas.

H. ANNUAL RECONCILIATION REPORT

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

COST OF GAS CLAUSE
(Continued)

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

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

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

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

5. A description of the imbalance payments made to and received from the Company's transportation customers within the service area, including monthly imbalances incurred, the monthly 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.

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

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

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

RATE CASE EXPENSE SURCHARGE

A. APPLICABILITY

The Rate Case Expense Surcharge (RCE) rate as set forth in Section (B) below is implemented pursuant to City Ordinances, other regulatory approval or by operation of law. This rate shall apply to the following rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") in the incorporated areas served in the Central-Gulf Service Area including Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas: 10, 20, 30, 40, 48, C-1, CNG-1, and T-1.

B. RCE RATE

All Ccf during each billing period: $ per Ccf

This rate will be in effect until all approved and expended rate case expenses are recovered under the applicable rate schedules. The Company will recover $ in actual expense and up to $ in estimated expense, not to exceed actual 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 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.

Initial Rate Schedule

Meters Read On and After
TBD

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

RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a 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. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

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

COST OF SERVICE RATE CHOICES

During each monthly billing period:

For Rate A

A customer charge per meter per month of	$14.00 plus
All Ccf per monthly billing period @	$0.55702 per Ccf

For Rate B

A customer charge per meter per month of	$27.58 plus
All Ccf per monthly billing period @	$0.10435 per Ccf

CUSTOMER CHOICE RATE PLACEMENT

Each customer's individual rate schedule will be determined based on the annual volume at the customer's service location for the prior twelve (12)-month period. An anticipated annual 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 choice for the new account.

If the customer's service location's annual volume is less than 360 Ccf, then the customer's account will be placed on Rate A.

If the customer's service location's annual volume is 360 Ccf or greater, then the customer's account will be placed on Rate B.

A customer may switch rate choices at any time during the year provided that the customer agrees to remain on the alternative rate for a period of no less than twelve (12) months after switching options. Changes will be effective with the Customer's next scheduled bill.

Supersedes Rate Schedule Dated	Meters Read On and After
June 14, 2019 (Central Texas Service Area) September 26, 2019 (Gulf Coast Service Area)	TBD

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

RESIDENTIAL SERVICE RATE
(Continued)

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

Taxes: Plus applicable taxes and fees related to above.

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

CONDITIONS

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

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE 2Z**

COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to all commercial customers and to customers not otherwise specifically provided for under any other rate schedule. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$53.33 plus
All Ccf per monthly billing period @	$0.12678 per Ccf

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

Taxes: Plus applicable taxes and fees related to above.

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

Supersedes Rate Schedule Dated	Meters Read On and After
June 14, 2019(Central Texas Service Area)	TBD
September 26, 2019 (Gulf Coast Service Area)	

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE 2Z**

COMMERCIAL SERVICE RATE
(Continued)

CONDITIONS

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

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE 3Z**

INDUSTRIAL SERVICE RATE

APPLICABILITY

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

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

TERRITORY

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$320.96 plus
All Ccf per monthly billing period @	$0.12703 per Ccf

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

Taxes: Plus applicable taxes and fees related to above.

Supersedes Rate Schedule Dated	Meters Read On and After
June 14, 2019 (Central Texas Service Area)	TBD
September 26, 2019 (Gulf Coast Service Area)	

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE 3Z**

INDUSTRIAL SERVICE RATE
(Continued)

CONDITIONS

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

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

PUBLIC AUTHORITY SERVICE RATE

APPLICABILITY

Applicable to any qualifying public authority, public and parochial schools and colleges, and to all facilities operated by Governmental agencies not specifically provided for in other rate schedules or special contracts. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$81.70 plus
All Ccf per monthly billing period @	$0.12551 per Ccf

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

Taxes: Plus applicable taxes and fees related to above.

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

Supersedes Rate Schedule Dated	Meters Read On and After
June 14, 2019 (Central Texas Service Area)	TBD
September 26, 2019 (Gulf Coast Service Area)	

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

PUBLIC AUTHORITY SERVICE RATE
(Continued)

CONDITIONS

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

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

PUBLIC SCHOOLS SPACE HEATING SERVICE RATE

APPLICABILITY

Applicable to public schools for space heating purposes. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$134.70 plus
All Ccf per monthly billing period @	$0.10012 per Ccf

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

Taxes: Plus applicable taxes and fees related to above.

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

Supersedes Rate Schedule Dated	Meters Read On and After
June 14, 2019 (Central Texas Service Area)	TBD

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

PUBLIC SCHOOLS SPACE HEATING SERVICE RATE
(Continued)

CONDITIONS

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

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

Central-Gulf 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 walk ways. The Company, in its sole discretion, shall determine if Customer's lighting equipment qualifies for this tariff and shall contract with Customer for the appropriate monthly charge based upon Customer's complete installation of gas lighting equipment. Gas service under this rate schedule is available only with the Company as the sole supplier of gas for Customer and is not available for resale to others or for standby or supplemental service. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

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

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	$ 0.10435 per Ccf
Commercial	$ 0.12678 per Ccf
Industrial	$ 0.12703 per Ccf
Public Authority	$ 0.12551 per Ccf

OTHER ADJUSTMENTS

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

Taxes: Plus applicable taxes and fees related to above.

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

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE C-1-ENV**
Central-Gulf Service Area **Page 1 of 2**

ELECTRICAL COGENERATION RATE

APPLICABILITY

Service under this rate schedule is available to any customers who use natural gas for the purpose of cogeneration or the use of fuel cell technology. 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

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of		$ 104.70 plus
For the First	5,000 Ccf/Month	$0.07720 per Ccf
For the Next	35,000 Ccf/Month	$0.06850 per Ccf
For the Next	60,000 Ccf/Month	$0.05524 per Ccf
All Over	100,000 Ccf/Month	$0.04016 per Ccf

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

Taxes: Plus applicable taxes and fees related to above.

Supersedes Rate Schedule Dated
June 14, 2019 (Central Texas Service Area)

Meters Read On and After
TBD

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE C-1-ENV**
Central-Gulf Service Area **Page 2 of 2**

ELECTRICAL COGENERATION RATE
(Continued)

CONDITIONS

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

This rate will not be available for standby use.

The curtailment priority of any customer served under this rate schedule shall be the same as the curtailment priority which would pertain if gas were used directly to provide energy for uses as defined and listed in the Company's curtailment plan.

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

Supersedes Rate Schedule Dated
June 14, 2019 (Central Texas Service Area)

Meters Read On and After
TBD

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

RATE SCHEDULE CNG-1-ENV
Page 1 of 2

COMPRESSED NATURAL GAS SERVICE RATE

APPLICABILITY

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

TERRITORY

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

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$ 192.63 plus
All Ccf per monthly billing period @	$0.06684 per Ccf

OTHER ADJUSTMENTS

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

Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Natural Event Response Rider: The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

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

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

Taxes: Plus applicable taxes and fees related to above.

Supersedes Rate Schedule Dated
June 14, 2019 (Central Texas Service Area)

Meters Read On and After
TBD

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

RATE SCHEDULE CNG-1-ENV
Page 2 of 2

COMPRESSED NATURAL GAS SERVICE RATE
(Continued)

CONDITIONS

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

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

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

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

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

Texas Gas Service Company, a Division of ONE Gas, Inc. **Rate Schedule 1-ENV**
Central-Gulf Service Area **Page 1 of 4**

COST OF GAS CLAUSE

A. APPLICABILITY

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

B. DEFINITIONS

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

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

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

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

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

<ins>Supersedes Rate Schedule Dated</ins>
<ins>1 dated September 8, 2017</ins> (Unincorporated Areas of the Central Texas Service Area)
<ins>1-ENV (GALV) dated May 9, 2016</ins> (Unincorporated Areas of Bayou Vista, Galveston, and Jamaica Beach, TX)
<ins>1-ENV (SJC) dated May 9, 2016</ins> (Unincorporated Areas of Groves, Nederland, Port Arthur, and Port Neches, TX)

<ins>Meters Read On and After</ins>
TBD

COST OF GAS CLAUSE
(Continued)

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

7. Reconciliation Account - The account maintained by the Company to assure that over time it will neither over nor under collect revenues as a result of the operation of the Cost of Gas Clause. Entries shall be made monthly to reflect: (a) the total amounts paid to the Company's supplier(s) for gas applicable to general service 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; (c) refunds, payments, or charges provided for herein or as approved by the regulatory authority; (d) amounts accrued pursuant to the treatment of imbalances under any transportation rate schedule(s); (e) total amount of Uncollectible Cost of Gas during the period; and (f) an adjustment, if necessary, for lost and unaccounted for gas during the period in excess of 5 percent of purchases.

8. 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 general service rate schedules, the Company shall bill each general service 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 general service sales volumes, adjusted for the effects of weather, growth, and conservation for the period beginning with the October billing cycle through the June billing cycle preceding the filing of the Reconciliation Audit. The Reconciliation Component so determined to collect any revenue shortfall or to return any excess revenue shall be applied, subject to refund, for a 9 month period beginning with the October billing cycle and continuing through the next June billing cycle at which time it will terminate.

E. INTEREST ON FUNDS

Concurrently with the Reconciliation Audit, the Company shall determine the amount by which the Cost of Gas was over or under collected for each month within the period of audit. The Company shall debit or credit to the Reconciliation Account for each month of the reconciliation period: (1) an amount equal to the outstanding over collected balance multiplied by interest of 6 percent per annum compounded monthly; or (2) an amount equal to the outstanding under collected balance multiplied by interest of 6 percent per annum

COST OF GAS CLAUSE
(Continued)

compounded monthly. The Company shall also be allowed to recover a carrying charge calculated based on the arithmetic average of the beginning and ending balance of gas in storage inventory for the prior calendar month times the authorized rate of return.

F. SURCHARGE OR REFUND PROCEDURES

In the event that the rates and charges of the Company's supplier are retroactively reduced and a refund of any previous payments is made to the Company, the Company shall make a similar refund to its general service customers. Similarly, the Company may surcharge its general service 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. 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 Reconciliation Component; (e) the revenue associated fees and taxes to be applied to revenues generated by the Cost of Gas; (f) the Cost of Gas calculation, including gains and losses from approved hedging activities for the month; and (g) the beginning and ending date of the billing period. The statement shall include all data necessary for the Regulatory Authority to review and verify the calculations of the Cost of Gas.

H. ANNUAL RECONCILIATION REPORT

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

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

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

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

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

**Rate Schedule 1-ENV
Page 4 of 4**

COST OF GAS CLAUSE
(Continued)

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

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

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

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

Supersedes Rate Schedule Dated
1 dated September 8, 2017 (Unincorporated Areas of the Central Texas Service Area)
1-ENV (GALV) dated May 9, 2016 (Unincorporated Areas of Bayou Vista, Galveston, and Jamaica Beach, TX)
1-ENV (SJC) dated May 9, 2016 (Unincorporated Areas of Groves, Nederland, Port Arthur, and Port Neches, TX)

Meters Read On and After
TBD

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

RATE CASE EXPENSE SURCHARGE

A. APPLICABILITY

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

B. RCE RATE

All Ccf during each billing period: $ per Ccf

This rate will be in effect until all approved and expended rate case expenses are recovered under the applicable rate schedules. The Company will recover $ in actual expense and up to $ in estimated expense, not to exceed actual expense. The Rate Case Expense Surcharge will be a separate line item on the bill.

C. OTHER ADJUSTMENTS

Taxes: Plus applicable taxes and fees related to above.

D. CONDITIONS

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

E. COMPLIANCE

The Company shall file an annual rate case expense reconciliation report within 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 Railroad Commission of Texas addressed to the Director of Oversight and Safety Division, Gas Services Department and referencing Gas Utilities Docket No. . Rate Case Expense Recovery Report. The report shall detail the monthly collections for RCE surcharge by customer class and show the outstanding balance. Reports for the Commission should be filed electronically at GUD_Compliance@rrc.texas.gov or at the following address:

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

Initial Rate Schedule

Meters Read On and After
TBD

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

EXCESS DEFERRED INCOME TAX CREDIT

A. APPLICABILITY

This Excess Deferred Income Tax Credit applies to all general service rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") currently in force in the Company's Central-Gulf Service Area within the incorporated and unincorporated areas of Austin, Bayou Vista, Beaumont, Bee Cave, Buda (environs only), Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas: 10, 20, 30, 40, 48, C-1, CNG-1, 1Z, 2Z, 3Z, 4H, 4Z, C-1-ENV, CNG-1-ENV, T-1, and T-1-ENV.

B. CALCULATION OF CREDIT

The annual amortization of the regulatory liability for excess deferred income taxes resulting from the Tax Cuts and Jobs Act of 2017 and in compliance with GUD No. 10695, will be credited to customers annually on a one-time, per bill basis and will show as a separate line item on the customer's bill until fully amortized.

EDIT CREDIT – The total amount, if any, of the credit in a given year will be determined by:

- The average rate assumption method ("ARAM") as required by the Tax Cuts and Jobs Act of 2017 Section 13001(d) for protected property; and
- A 10-year amortization for nonprotected property.

TRUE-UP ADJUSTMENT – The Excess Deferred Income Tax credit shall be trued-up annually. The True-Up Adjustment will be the difference between the amount of that year's EDIT Credit and the amount actually credited to customers.

EDIT CREDIT PER CUSTOMER – The EDIT credit per customer will be determined by allocating that year's credit, plus/minus any prior year true up adjustment, among the customer classes utilizing the same class revenue allocation as approved in the most recent general rate case, and then by dividing each class's portion by the number of customers in that class.

C. EDIT CREDIT PER CUSTOMER

Residential:	$
Commercial:	$
Industrial:	$
Public Authority:	$
Public Schools Space Heat:	$

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

D. OTHER ADJUSTMENTS

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

Initial Rate Schedule

Meters Read On and After
TBD

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

EXCESS DEFERRED INCOME TAX CREDIT
(Continued)

E. <u>ANNUAL FILING</u>

The Company shall make a filing with the Commission each year no later than December 31, including the following information:

a. the total dollar amount of that year's EDIT Credit;
b. the total dollar amount actually credited to customers;
c. true-up amount, if any, due to the difference between items a. and b., above;
d. the amount of the upcoming year's EDIT Credit; and
e. the amounts of the upcoming year's EDIT Credit per Customer.

F. <u>CONDITIONS</u>

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

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

HURRICANE HARVEY SURCHARGE

A. APPLICABILITY

The Hurricane Harvey Surcharge rate as set forth in Section (B) below is for the recovery of losses incurred by the Company as a direct result of Hurricane Harvey and not recoverable from any other source. The rate shall apply to the following gas sales and standard transportation rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") currently in force in the Company's Central-Gulf Service Area within the incorporated and unincorporated areas of Austin, Bayou Vista, Beaumont, Bee Cave, Buda (environs only), Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas: 10, 20, 30, 40, 48, C-1, CNG-1, 1Z, 2Z, 3Z, 4H, 4Z, C-1-ENV, CNG-1-ENV, T-1, and T-1-ENV.

B. SURCHARGE RATE

All Ccf during each billing period: $0.00182 per Ccf

This rate will be in effect until all approved and expended Hurricane Harvey costs and associated rate case expenses are recovered under the applicable rate schedules.

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.

E. COMPLIANCE

TGS shall file a reconciliation report annually on or before December 31, commencing in 2020. TGS shall file the report with the Railroad Commission of Texas, addressed to the Director of the Oversight and Safety Division and referencing Gas Utilities Docket No. _____, Hurricane Harvey Surcharge Recovery Report. The report shall include:

(1) The volumes used by month by customer class during the applicable period,
(2) The amount of surcharge recovered, by month
(3) The outstanding balance, by month

Initial Rate Schedule

Meters Read On and After
TBD

NATURAL EVENT RESPONSE (NER) RIDER

PURPOSE

The purpose of this Natural Event Response Rider is to authorize Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company") to defer and seek recovery of the reasonable and necessary expenses incurred by the Company in responding to and restoring natural gas service following a hurricane, tropical storm, tornado, earth quake, ice storm, flood or other wind-related or water-related event ("Event"), net of any related insurance reimbursements. These natural event response expenses shall be deferred when incurred and subsequently recovered through a separate monthly volumetric charge (the Natural Event Response or "NER" 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. Regular Company labor and capital expenditures associated with a Natural Event Response 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 throughout the Company's Central-Gulf Service Area ("CGSA"), both within the incorporated municipal limits of Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley and West Lake Hills and Yoakum, Texas (collectively, the "CGSA Cities"), and in the unincorporated areas (environs) adjacent to the CGSA Cities.

QUALIFYING EXPENSES

This Rider applies only to expenses incurred in response to a defined natural event in the CGSA, net of any insurance reimbursements associated with that Event. The operating and maintenance expense items that qualify for recovery under this Rider shall include contractor costs and Company overtime labor; travel, hotel and meal expenses; vehicle expenses; communication expenses; tools, materials and supplies; and any other operating and maintenance expenses reasonably necessary to safely and effectively respond to an event and restore natural gas service. Capital expenditures by the Company, and the regular labor cost of Texas Gas Service Company employees shall not be recovered under this Rider. Lost revenue due to an Event and insurance reimbursements for lost revenue shall not be recovered under this Rider.

NATURAL EVENT RESPONSE (NER) RIDER
(Continued)

DEFERRED ACCOUNTING

The Company is authorized and directed to defer, as a regulatory asset, all Natural Event Response expenses incurred starting on January 1, 2020, and all related insurance reimbursements and 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.

REQUEST FOR SURCHARGE

Following a defined natural event, the Company shall file a report with the Commission and the CGSA Cities showing all expenses incurred in response to the event, all related insurance reimbursements, and a proposed surcharge calculated as set forth below. The report shall separately identify and list such expenses by account number, expense type and project number. The Commission and the CGSA Cities shall review the report, request supporting documentation, and approve an appropriate surcharge within 120 days.

CALCULATION OF NER SURCHARGES

The Natural Event Response Surcharges established under this Rider shall be designed so as to recover the Total Natural Event Response Expense incurred due to a defined Event, over a proposed recovery period in years which may vary by Event. The surcharge shall be calculated as follows:

The Total NER Expense shall be divided by the proposed recovery period to produce the annual NER Expense.

$$\text{Annual NER Expense} = \frac{\text{Total NER Expense}}{\text{Proposed Recovery Period (Years)}}$$

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

$$\text{NER Surcharge} = \frac{\text{Annual NER Expense}}{\text{Estimated Annual Usage}}$$

The surcharge thus calculated and approved for each event shall remain in place until all approved costs under that event are recovered.

NATURAL EVENT RESPONSE (NER) RIDER
(Continued)

ANNUAL REPORT

On or before January 31st after each calendar year, the Company shall file a report verifying the prior year's collections under this Rider. TGS shall file the report with the CGSA Cities and with the Railroad Commission of Texas, addressed to the Director of the Oversight and Safety Division and referencing the Gas Utilities Docket number(s) approving each surcharge. The report shall include:

1. The total amount to be recovered
2. The amounts collected during the prior period
3. The volumes used by month by customer class during the applicable period;
4. The amount of surcharge recovered, by month;
5. The outstanding balance by month;
6. Any credits or other offset for over-recovery; and
7. The remaining balance to be recovered

NOTICE TO AFFECTED CUSTOMERS

When requesting a surcharge under this Rider as set forth above, the Company shall provide written notice to each affected customer of (a) the proposed NER Surcharge ,(b) the number of years the surcharge is expected to be in effect, and (c) 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 English with Spanish translation available on request, 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. 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.

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

NATURAL EVENT RESPONSE RIDER

A. APPLICABILITY

The Natural Event Response ("NER") surcharge rate as set forth in Section (B) below is for the recovery of costs associated with the operation and maintenance expenses resulting from the Company's response to a natural event as defined in Rate Schedule NER. The rate shall apply to the following gas sales and standard transportation rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. currently in force in the Company's Central-Gulf Service Area within the incorporated and unincorporated areas of of Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley and West Lake Hills and Yoakum, Texas: 10, 20, 30, 40, 48, C-1, CNG-1, T-1, 1Z, 2Z, 3Z, 4Z, 4H, C-1-ENV, CNG-1-ENV and T-1-ENV.

B. SURCHARGE RATE

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

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.

Initial Rate Schedule

Meters Read On and After
TBD

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

PIPELINE INTEGRITY TESTING (PIT) RIDER

PURPOSE

The purpose of this Pipeline Integrity Testing Rider is to promote the public interest in pipeline safety by enabling Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company") to recover the reasonable and necessary Pipeline Integrity Safety Testing expenses incurred by the Company during the prior year (including contractor costs but excluding the labor cost of Texas Gas Service Company employees. These legally mandated operating and maintenance expenses shall be recovered through a separate monthly volumetric charge (the Pipeline Integrity Testing or "PIT" Surcharge) that shall be shown as a separate line item on the customer's monthly bill and calculated for each customer class as described below. Capital expenditures associated with the Pipeline Integrity Program shall continue to be recovered through base rates and any interim rate adjustments implemented pursuant to Section 104.301 of the 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 throughout the Company's Central-Gulf Service Area ("CGSA"), both within the incorporated municipal limits of Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas (collectively, the "CGSA Cities"), in the environs area of Buda, Texas, and in the unincorporated areas (environs) adjacent to the CGSA Cities.

QUALIFYING EXPENSES

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

Supersedes Rate Schedule Dated
October 26, 2016 (Cities of Austin, Bee Cave, Cedar Park, Dripping Springs, Kyle, Lakeway, Rollingwood, Sunset Valley, and West Lake Hills, TX)
January 6, 2017 (Cities of Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum, TX)
November 23, 2016 (Unincorporated Areas of the Central Texas Service Area)

Meters Read On and After
TBD

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE PIT**
Central-Gulf Service Area **Page 2 of 3**

PIPELINE INTEGRITY TESTING (PIT) RIDER
(Continued)

CALCULATION OF PIT SURCHARGES

The Pipeline Integrity Testing Surcharges established under this Rider shall be designed so as to recover the Total Testing Expense incurred in the prior year for Pipeline Integrity Safety Testing, except that qualifying expenses incurred in 2019 and 2020 shall be included for recovery in the first filing, and shall be calculated as follows:

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

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

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

ANNUAL RECONCILIATION

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

DEFERRED ACCOUNTING

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

PIPELINE INTEGRITY TESTING (PIT) RIDER
(Continued)

ANNUAL REPORT & APPLICABLE PSCC

On or before February 21st after each calendar year, the Company shall file a report with the Commission and the CGSA Cities showing all Pipeline Integrity Safety Testing expenses incurred during the previous calendar year and verifying the prior year's collections and any underrecoveries or overrecoveries accruing to date under this Rider. The report shall separately identify and list such expenses by account number and project number. Prior to the effective date of this Rider and on or before February 21st of each succeeding year while this Rider is in effect, the Company shall also file an Addendum to this Rider with the Commission and the CGSA Cities (a) identifying the PIT Surcharges that will be applied during the ensuing 12-month recovery period from April 1st through March 31st, 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. The Company shall also file an affidavit annually with the Commission and the CGSA Cities certifying that notice has been provided to customers in this manner. The notice shall be presumed to be complete three calendar days after the date the separate mailing or billing statement is deposited in a postage-paid, properly addressed wrapper in a post office or official depository under care of the United States Postal Service. The initial notice shall be filed with, reviewed, and approved by the regulatory authority, and each subsequent notice shall follow the same format as that of the approved initial notice.

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

PIPELINE INTEGRITY TESTING (PIT) SURCHARGE RIDER

A. APPLICABILITY

The Pipeline Integrity Testing Surcharge (PIT) rate as set forth in Section (B) below is for the recovery of costs associated with pipeline integrity testing as defined in Rate Schedule PIT. This rate shall apply to the following rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. (Company) in the incorporated and unincorporated areas of and adjacent to the Central-Gulf Service Area (CGSA): 10, 20, 30, 40, 48, C-1, CNG-1, T-1, 1Z, 2Z, 3Z, 4Z, 4H, C-1-ENV, CNG-1-ENV and T-1-ENV.

B. PIT RATE

$0.XXXXX 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.

Supersedes Rate Schedule Dated
March 29, 2019 (Central Texas Service Area)

Meters Read On and After
TBD

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 NATURAL 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;

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

RATE SCHEDULE PSF
Page 2 of 3

PIPELINE SAFETY PROGRAM FEES
(Continued)

(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;

(D) shall not exceed $1.00 per service or service line ***(For the calendar year 2018 annual pipeline safety and regulatory program fee, billed effective with meters read on and after March 29, 2019, 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 Gas Services Division and the Pipeline 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.

Supersedes Same Sheet Dated
March 27, 2018

Meters Read On and After
March 29, 2019

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

RATE SCHEDULE PSF
Page 3 of 3

PIPELINE SAFETY PROGRAM FEES
(Continued)

(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.

(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 Commission's Gas Services Division and the Pipeline 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

Supersedes Same Sheet Dated
March 27, 2018

Meters Read On and After
March 29, 2019

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

RATE SCHEDULE WNA
Page 1 of 2

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. ("Company") in the incorporated and unincorporated areas served in the Central-Gulf Service Area including Austin, Bayou Vista, Beaumont, Bee Cave, Buda (environs only), Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas: Rate Schedules 10, 1Z, 20, 2Z, 40, 4Z, 48 and 4H. 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:

Supersedes Rate Schedule Dated
October 26, 2016 (Cities of Austin, Bee Cave, Cedar Park, Dripping Springs, Kyle, Lakeway, Rollingwood, Sunset Valley, and West Lake Hills, TX)
January 6, 2017 (Cities of Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum, TX)
November 23, 2016 (Unincorporated Areas of the Central Texas Service Area)
May 9, 2016 (Gulf Coast Service Area)
May 22, 2019 (City of Beaumont)

Meters Read On and After
TBD

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

RATE SCHEDULE WNA
Page 2 of 2

WEATHER NORMALIZATION ADJUSTMENT CLAUSE
(Continued)

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

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

CB = Number of customers billed for the billing period.

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

Austin, Bee Cave, Buda (environs only), Cedar Park, Dripping Springs, Kyle, Lakeway, Rollingwood, Sunset Valley, and West Lake Hills:
Residential 0.15498; Commercial 0.38392; Public Authority 1.94154; Public Schools 3.95052

Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum:
Residential 0.14213; Commercial 0.21988; Public Authority 0.95317

Bayou Vista, Galveston, and Jamaica Beach:
Residential 0.18569; Commercial 0.44273; Public Authority 3.44053

Beaumont, Groves, Nederland, Port Arthur, and Port Neches:
Residential 0.17379; Commercial 0.28946; Public Authority 2.28489

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.

Supersedes Rate Schedule Dated
October 26, 2016 (Cities of Austin, Bee Cave, Cedar Park, Dripping Springs, Kyle, Lakeway, Rollingwood, Sunset Valley, and West Lake Hills, TX)
January 6, 2017 (Cities of Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum, TX)
November 23, 2016 (Unincorporated Areas of the Central Texas Service Area)
May 9, 2016 (Gulf Coast Service Area)
May 22, 2019 (City of Beaumont)

Meters Read On and After
TBD

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE T-1**
Central-Gulf Service Area **Page 1 of 3**

TRANSPORTATION SERVICE RATE

APPLICABILITY

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

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

AVAILABILITY

Natural gas service under this rate schedule is available to any individually metered, non-residential customer for the transportation of customer owned natural gas through the Company's Central-Gulf Service Area distribution system which includes the incorporated areas of Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas. 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	$ 265.33 per month
Industrial	$ 520.96 per month
Public Authority	$ 104.70 per month
Public Schools Space Heat	$ 234.70 per month
Compressed Natural Gas	$ 217.63 per month
Electrical Cogeneration	$ 104.70 per month

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE T-1**
Central-Gulf Service Area **Page 2 of 3**

TRANSPORTATION SERVICE RATE
(Continued)

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

Commercial	-	$ 0.12678 per Ccf
Industrial	-	$ 0.12703 per Ccf
Public Authority	-	$ 0.12551 per Ccf
Public Schools Space Heat	-	$ 0.10012 per Ccf
Compressed Natural Gas	-	$ 0.06684 per Ccf

Electrical Cogeneration	
For the First 5,000Ccf/month	$ 0.07720 per Ccf
For the Next 35,000 Ccf/month	$ 0.06850 per Ccf
For the Next 60,000 Ccf/month	$ 0.05524 per Ccf
All Over 100,000 Ccf/month	$ 0.04016 per Ccf

ADDITIONAL CHARGES:

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

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

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

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

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

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

7) The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

8) The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

Supersedes Rate Schedule Dated
June 3, 2019 (Central Texas Service Area - Austin Only)
June 14, 2019 (Central Texas Service Area - All Other Incorporated Areas)
July 29, 2019 (Gulf Coast Service Area)
May 22, 2019 (City of Beaumont)

Meters Read On and After
TBD

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE T-1**
Central-Gulf Service Area **Page 3 of 3**

TRANSPORTATION SERVICE RATE
(Continued)

9) The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

SUBJECT TO

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

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

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

Supersedes Rate Schedule Dated
June 3, 2019 (Central Texas Service Area - Austin Only)
June 14, 2019 (Central Texas Service Area - All Other Incorporated Areas)
July 29, 2019 (Gulf Coast Service Area)
May 22, 2019 (City of Beaumont)

Meters Read On and After
TBD

TRANSPORTATION SERVICE RATE

APPLICABILITY

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

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

AVAILABILITY

Natural gas service under this rate schedule is available to any individually metered, non-residential customer for the transportation of customer owned natural gas through the Company's unincorporated areas of the Central-Gulf Service Area distribution system which includes the environs of Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas. Such service shall be provided at any point on the Companys 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	$ 265.33 per month
Industrial	$ 520.96 per month
Public Authority	$ 104.70 per month
Public Schools Space Heat	$ 234.70 per month
Compressed Natural Gas	$ 217.63 per month
Electrical Cogeneration	$ 104.70 per month

Supersedes Rate Schedule Dated
June 14, 2019 (Central Texas Service Area)
September 26, 2019 (Gulf Coast 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	-	$ 0.12678 per Ccf
Industrial	-	$ 0.12703 per Ccf
Public Authority	-	$ 0.12551 per Ccf
Public Schools Space Heat	-	$ 0.10012 per Ccf
Compressed Natural Gas	-	$ 0.06684 per Ccf
Electrical Cogeneration	-	
For the First 5,000Ccf/month		$ 0.07720 per Ccf
For the Next 35,000 Ccf/month		$ 0.06850 per Ccf
For the Next 60,000 Ccf/month		$ 0.05524 per Ccf
All Over 100,000 Ccf/month		$ 0.04016 per Ccf

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

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

4) The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT.

5) The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.

6) The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.

7) The billing shall reflect adjustments in accordance with provisions of the Natural Event Response Rider, Rate Schedule NER.

<u>Supersedes Rate Schedule Dated</u>	<u>Meters Read On and After</u>
June 14, 2019 (Central Texas Service Area)	TBD
September 26, 2019 (Gulf Coast Service Area)	

TRANSPORTATION SERVICE RATE
(Continued)

SUBJECT TO

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

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

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

GENERAL TERMS AND CONDITIONS FOR TRANSPORTATION SERVICE

1.1 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.

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.
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.

GENERAL TERMS AND CONDITIONS FOR TRANSPORTATION SERVICE (Continued)

Cumulative Tolerance Limit:	Shall mean the percent of aggregate historical annual deliveries of a Qualified Supplier's Aggregation Area pool of customers for the most recent year ended on June 30. The Company, at its sole discretion, may make adjustments to the Cumulative Tolerance Limit.
Customer:	Any person or organization now being billed for gas service whether used by him or her, or by others.
Day or Gas Day:	Shall mean the 24-hour period commencing at 9:00 a.m. (Central Standard Time) on one calendar day and ending at 9:00 a.m. (Central Standard Time) the following calendar day.
Dekatherm (Dth):	Shall mean 1,000,000 Btu's (1 MMBtu). This unit will be on a dry basis.
Electrical Cogeneration 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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

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

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

Transportation Form: Shall mean the Company approved selection of transportation service document.

Transportation Rate Schedule: A rate schedule designed for service to any Customer for the transportation of Customer-owned natural gas through the Company's distribution system.

Transportation Service: The transportation by the Company of natural gas owned by someone other than the Company through the Company's distribution system.

Week: Shall mean a period of 7 consecutive Days beginning at 9:00 a.m. Central Standard Time on each Monday and ending at the same time on the next succeeding Monday.

Year: Shall mean a period of 365 consecutive Days, or 366 consecutive Days when such period includes a February 29.

1.3 COMPANY'S RESPONSIBILITY

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

a) In no event shall Company be required to expand, modify, construct, rearrange, or change the operations of the Pipeline System in order to receive gas from or on behalf of Customer or in order to deliver gas to Customer at any existing Points of Delivery. 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.

1.4 CUSTOMER'S RESPONSIBILITY

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

a) Gas received by Company for the Customer shall be free from all adverse claims, liens, and encumbrances;

b) 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;

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

c) 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;

d) 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;

e) Customer acknowledges the Qualified Supplier's responsibilities under Section 1.5;

f) 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;

g) 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

h) 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.

1.5 QUALIFIED SUPPLIER’S RESPONSIBILITY

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

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

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

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

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 Customer 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.

1.6 IMBALANCES

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

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

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.

GENERAL TERMS AND CONDITIONS FOR TRANSPORTATION SERVICE (Continued)

d) A proportional share of any upstream pipeline transportation service 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). Proceeds from this charge will be credited to the Reconciliation Account. The Company will bill Qualified Supplier for these charges and penalties manually on a separate bill. Payment shall be required in accordance with applicable Rules of Service.

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

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

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

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

Supersedes Rate Schedules Dated
October 26, 2016 (Cities of Austin, Bee Cave, Cedar Park, Dripping Springs, Kyle, Lakeway, Rollingwood, Sunset Valley, and West Lake Hills, TX)
January 6, 2017 (Cities of Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum, TX)
November 23, 2016 (Unincorporated Areas of the Central Texas Service Area)
May 9, 2016 (Incorporated and Unincorporated Areas of the Gulf Coast Service Area)
May 22, 2019 (City of Beaumont)

Meters Read On and After
TBD

RULES OF SERVICE

CENTRAL-GULF SERVICE AREA

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

Effective for Meters Read On and After
TBD

Supersedes and Replaces "Incorporated Central Texas Service Area" (Cities of Austin, Bee Cave, Cedar Park, Dripping Springs, Kyle, Lakeway, Rollingwood, Sunset Valley, and West Lake Hills, TX) dated October 26, 2016;
"Incorporated Central Texas Service Area" (Cities of Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum, TX) dated January 6, 2017;
"Unincorporated Areas of the Central Texas Service Area" dated November 23, 2016;
"Incorporated and Unincorporated Gulf Coast Service Area" dated May 9, 2016;
"Incorporated Areas of Beaumont, TX" dated May 22, 2019

Communications Regarding this Tariff
Should Be Addressed To:

Texas Gas Service Company, a Division of ONE Gas, Inc.
5613 Avenue F
Austin, Texas 78751

OR

Texas Gas Service Company, a Division of ONE Gas, Inc.
4201 39th Street
Port Arthur, TX 77642

OR

Texas Gas Service Company, a Division of ONE Gas, Inc.
402 33rd Street
Galveston, TX 77750

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

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GENERAL STATEMENT

1.1 TARIFF APPLICABILITY

Texas Gas Service Company, a Division of ONE Gas, Inc. is a gas utility operating within the State of Texas. This Tariff applies to Texas Gas Service Company, a Division of ONE Gas, Inc.'s Central-Gulf Service Area, comprising the Cities and environs of Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, and the environs of Buda, Texas. This Tariff supersedes and replaces all tariffs previously approved and applied in the Central Texas, Gulf Coast Service Areas and the City of Beaumont.

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

1.2 RATE SCHEDULES

All Customers shall be served under rate schedules filed with the municipality or Railroad Commission of Texas. Customers shall be assigned to rate schedules in accordance with the class of the particular Customer, the usage which will be made of the gas and that Customer's volume requirements. The Company shall advise an Applicant or Customer regarding the most advantageous rate for his or her 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.

GENERAL STATEMENT (Continued)

1.3 DEFINITIONS (Continued)

Average Day Usage:	The gas demand of a given Customer for gas in any one month divided by 30. Gas demand is considered to be equivalent to consumption during each billing month, provided however, that when service has been curtailed, demand shall be considered to be actual consumption plus estimated curtailment during the period.
Blanket Builder:	A builder or someone acting for a builder who is invoiced for 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.
Customer:	Any person or organization now being billed for gas service whether used by him or her, or by others.
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.

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

GENERAL STATEMENT (Continued)

1.3 DEFINITIONS (Continued)

Day or Gas Day:	Shall mean the 24-hour period commencing at 9:00 a.m. (central clock time) on one calendar day and ending at 9:00 a.m. (central clock 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 below ground inside the natural gas service line between the main and the meter intended to reduce the risk of accidents in limited situations.
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.

GENERAL STATEMENT (Continued)

1.3 DEFINITIONS (Continued)

Industrial Service:	Service to Consumers engaged primarily in a process which changes raw or unfinished materials into another form of product. This classification shall embrace all Consumers included in Division A (except Major Groups 01 and 02) and Division D of the Standard Industrial Classification Manual.
Irrigation or Irrigation Pumping Service:	(SIC Division A - Major Group 01) who use gas for operating engine-driven pumping equipment.
Mcf:	Shall mean one thousand (1,000) cubic feet of Gas.
Month:	Shall mean the period beginning at 9:00 a.m. central clock time on the first Day of each calendar month and ending at 9:00 a.m. Central clock time on the first Day of the next succeeding calendar month.
Monthly Tolerance Limit:	Shall mean five percent (5%) of the aggregate deliveries for a Qualified Suppliers Aggregation Area pool of customers for such month.
Optional Rate Schedule:	A General Rate Schedule which may be selected by a Customer in lieu of another general schedule but which may require installation of special equipment.
Overtime Rate:	The fee charged by the Company to perform work outside its normal business hours or on holidays and includes changes to previously scheduled work that must be performed outside the Company's normal business hours.
Payment in Kind (PIK):	Shall mean a reimbursement for lost and unaccounted for gas.
PDA:	Shall mean a predetermined allocation method.
Pipeline System:	Shall mean the current existing utility distribution facilities of the Company located in the State of Texas.
Point of Delivery:	Shall mean the point or points where gas is delivered from the Pipeline System to Customer.
Point of Receipt:	Shall mean the point or points where the Company shall receive Gas into the Pipeline System from Customer.
Point Operator:	Shall mean the person or entity that controls the Point of Receipt or Point of Delivery.

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

GENERAL STATEMENT (Continued)

1.3 DEFINITIONS (Continued)

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

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

Section 2. [Reserved for future rules]

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

Section 3: RATES AND UTILITY CHARGES
Please see current Rate Schedules on file with each applicable Regulatory Authority.

CONDITION OF SERVICE

4.1 PROVISION OF SERVICE

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

4.2 FEES AND CHARGES

All fees and charges made by the Company to provide and maintain utility services 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 - except, 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 will reestablish service within the shortest possible time consistent with prudent operating principles so that the smallest number of Customers is affected.

  ii) The Company shall make reasonable provisions to meet emergencies resulting from failure of service and will 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 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.

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

CONDITION OF SERVICE (Continued)

4.4 CONTINUITY OF SERVICE (Continued)

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

d) The procedure under which curtailments of service will be made is described in the Curtailment Plan on file with the Railroad Commission of Texas.

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

4.5 AVAILABILITY OF TARIFF

A copy of this Tariff including all applicable rates 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. Upon the request of any Customer or Applicant, the Company shall make copies of the Tariff which may be purchased by the Customer or Applicant through TGS's customer service. The Company may charge a fee for each copy not in excess of the Company's reasonable cost to reproduce the material.

4.6 CUSTOMER INFORMATION

The Company shall make available, during normal business hours, such additional information on Rates and Services as any Customer or Applicant may reasonably request. Upon any Customer's request, the Company shall inform the Customer how to read the Customer's meter. The Company shall annually provide each Customer with notice of the availability of a concise description in English and Spanish of the Customer's rights and the Company's obligations under this Tariff. A new Customer shall be provided with an informational brochure in the mail after requested service initiation or included with the first bill mailed.

4.7 CUSTOMER COMPLAINTS

Upon receipt of a complaint, either in writing or by telephone, from the Regulatory Authority on behalf of a Customer, the Company will make a suitable investigation and advise the Regulatory Authority and complainant of the results thereof. An initial response must be made by the next business day. The Company must make a final and complete response within 15 days from the date of the complaint, unless additional time is granted within the 15 day period. Each complainant shall be advised of his or her right to file the complaint with the Regulatory Authority if not satisfied by the Company.

CONDITION OF SERVICE (Continued)

4.8 LIMITATION OF LIABILITY

The Customer assumes all responsibility for all facilities and their installation, maintenance, operation, functionality, testing and condition thereof on the Customer's side of the point of delivery of gas to the property of the Customer or to the premises of the Consumer, as defined in Section 6.2. The Company is not liable to a Customer, and Customer shall indemnify, hold harmless, and defend the Company and its employees or agents from any and all claims or liability for personal injury, damage to property, or any incidental, consequential, business interruption, or other economic damages or losses in any manner directly or indirectly connected to, arising from, or caused by acts or omissions of any person or party on the Customer's side of said point of delivery, as defined in Section 6.2.

The Company shall be liable to the Customer or Consumer only for personal injury or property damages from or caused directly 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 personal injury, property damages, or any other loss or damages arising from or caused by the negligent or intentional act or omission of any person, other than an employee of the Company, who adjusts, repairs, disconnects, changes, alters, or tampers with the Company's meter or facilities in any way.

The Company shall be liable to third parties only for personal injury or property damage directly arising from the negligence or gross negligence of the Company or its employees when acting within the scope of their employment.

In no event shall the Company or its employees be liable for incidental, consequential, business interruption, or other economic damages or losses of Customer, Consumer, or third parties in any manner, directly or indirectly, arising from, caused by, or growing out of the interruption or termination of gas utility service.

The Customer shall make or procure conveyance to the Company of perpetual right-of-way across the property owned or controlled by the Customer that is satisfactory to the Company, provides clear access to Company's facilities, and enables the Company to provide service to Customer's property or the premises of the Consumer.

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 SPECIAL CONTRACTS

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

5.3 TEMPORARY SERVICE

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

5.4 FEES AND CHARGES

The Company shall charge a non-refundable fee to each Applicant to compensate for the cost involved in initiation or reconnection of service or when service is transferred from one name to another at any location, or whenever a meter is reset or relocated on the same premises at the request of the Customer, all as specified in Section 21.1 of this Tariff.

Whenever the Applicant requests expedited service, the Company will accomplish the work as expeditiously as possible and the Customer will be charged at the Company's approved rate for service work. Expedited service and the charges therefore shall be made only on request of the Applicant. Whenever service is furnished from the facilities of a third party and the Company must pay any special fees to that third party, the Company may, at its option, pass that charge plus 20 percent for handling through to the Applicant requesting service. See Section 21.1 relating to fees for the above.

5.5 ESTABLISHMENT OF CREDIT

Each Applicant for service shall be required to make a security deposit in accordance with Section 10 of this Tariff to establish and maintain satisfactory credit. These deposits shall be computed in the same manner for the same class of service, provided however, that a deposit shall be waived if:

INITIATION OF SERVICE (Continued)

5.5 ESTABLISHMENT OF CREDIT (Continued)

a) The Applicant has been a Customer for the same kind of service within the last two years and did not have more than one occasion in which a bill for service from any such utility service account was delinquent and no disconnection for non-payment was made;

b) The Applicant furnishes an acceptable letter of credit;

c) The Applicant demonstrates a satisfactory credit rating by presentation of satisfactory credit references capable of quick, inexpensive verification (applicable to residential Customers only);

d) The Applicant is 65 years of age or older and has no outstanding balance for natural gas utility service which accrued within the last two years (applicable to residential Customers only);

e) The application is made for or guaranteed by an agency of the federal, state or local government; or

f) The Applicant has been determined to be a victim of family violence as defined by TEX. FAM. CODE ANN., §71.004. This determination shall be evidenced by the applicant/s submission of a certification letter developed by the Texas Council on Family Violence (made available on its Web site).

5.6 GROUNDS FOR REFUSAL TO SERVE

The Company may refuse service to any Applicant for any of the following reasons:

a) Failure to pay fees, advances or contributions or to make any deposit required for service under this Tariff;

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

c) Existence of an unsafe condition such as a leak in the Applicant's piping system which, in Company's sole opinion, may endanger life or property;

d) The Applicant is indebted to the Company for the same class of utility service at the same or another service location within the Company's system; or

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

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

INITIATION OF SERVICE (Continued)

5.7 REASONABLE TIME

The Company shall have a reasonable amount of time to institute service following application therefore or execution of an agreement for service. The time may vary depending on approvals and permits required, the extent of the facilities to be built, and the Company's workload at the time.

METERING AND DELIVERY OF GAS

6.1 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. It may be necessary for the Company to install bollards or guard posts around the meters for safety.

6.2 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.

6.3 MULTIPLE METERS

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

6.4 CONNECTION TO COMPANY FACILITIES

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

INSTALLATION OF EQUIPMENT

7.1 EQUIPMENT FURNISHED BY THE COMPANY

The Company shall furnish and install at its expense, the service pipe from the Company's existing main to the property line nearest the meter and the equipment related thereto, including meter valve and service regulator. Whenever the meter is located at any point other than the property line, the Company shall determine the estimated cost of that portion of the service between the property line and the meter set. This estimate shall be based on the size and footage to be installed and charged in accordance with Section 8 and other applicable provisions of this Tariff. Although affixed to or buried in the Customer's property, the entire service and meter set shall become the property of the Company and shall be operated and maintained by the Company.

7.2 EQUIPMENT FURNISHED BY THE APPLICANT

The Applicant shall furnish and install at his or her expense, all piping and equipment required to conduct and utilize the gas furnished, from the outlet of the meter set to the point(s) of utilization and those portions of the service line and meter set not furnished by the Company as described in Section 7.1 above. The adequacy, safety and compliance with applicable codes and ordinances shall be the responsibility of the Applicant and no action of the Company in accordance with this Tariff shall release the Applicant of the responsibility for the facilities installed by him or her.

7.3 STATUTES, CODES, AND ORDINANCES

All piping and installations owned by the Applicant shall comply with all applicable legal requirements, whether federal, state, county, municipal, or otherwise, and shall be properly designed for the pressures and volumes to be handled. In those locations where there are no applicable state or local requirements, the applicable provisions of the National Fuel Gas Code 54; ANSI Z223.1 and any amendments thereto shall apply.

7.4 CHECKS AND TESTS

The Company shall have the right to check new installations prior to initiation of service and to make any test of the Applicant's facilities it deems necessary, at no charge to the customer.

7.5 REFUSAL TO SERVE

The Company shall refuse service to any Applicant who refuses entry for observation or whose facilities do not comply with the applicable provisions of this Tariff. The right to refuse service shall terminate with the correction of the condition(s) which was cause for refusal. Initiation of service, however, shall not be considered to be acceptance or approval by the Company of such facilities.

EXTENSION OF FACILITIES

8.1 EXTENSION OF MAINS

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

8.2 DESIGN AND COST OF FACILITIES

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

8.3 ALLOWANCE FOR NEW BUSINESS

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

8.4 ADVANCES

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

8.5 CONSTRUCTION OF FACILITIES

As soon as practical after the advance has been paid or it has been determined that no advance will be required, the Company shall begin construction of the required facilities and thereafter prosecute the

EXTENSION OF FACILITIES (Continued)

8.5 CONSTRUCTION OF FACILITIES (Continued)

work with reasonable diligence. The Company shall not be responsible for delays in the construction of the facilities occasioned by events or conditions reasonably beyond the Company's control. Whenever the construction of the new facilities requires the acquisition of rights-of-way across the Applicants(s) land(s), these rights-of-way shall be provided by the Applicant(s) in the Company's name and on its form at no cost to the Company (except for fees involved in the recording of documents).

8.6 REVIEW OF ADVANCES

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

8.7 REFUND LIMITATIONS

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

8.8 DELIVERY OF REFUNDS

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

CUSTOMER-OWNED SYSTEMS

9.1 INDIVIDUALLY METERED SYSTEMS

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

9.2 MASTER METERS

The Company shall provide service through a master meter into the piping systems of others to be distributed to more than one Consumer, except when the gas served is resold to those Consumers on either a commodity or separate cost of service basis; provided, however, that those Customers purchasing gas for redistribution to the Customer's own tenants only on the Customer's premises may separately meter each tenant distribution point for the purpose of prorating the Consumer's actual purchase price of gas delivered among the various tenants on a per unit basis, and further provided that the provisions of this Section 9 shall not preclude the Company from supplying natural gas to a third party for resale to the public as fuel for natural gas powered vehicles (NGV's).

SECURITY DEPOSITS

10.1 REQUIREMENTS

The Company shall require a security deposit from any present or prospective Customer in accordance with Sections 5.5 and 18.1 of this Tariff to guarantee payment of bills, and from any present Customer who during the last 12 consecutive months has on more than one occasion paid their utility bill after becoming delinquent. However, the deposit requirement may, at the option of the Company be based on annual usage experienced at the particular address with application of one-sixth of the annual amount as determined as the required deposit. If actual use is at least twice the amount of the estimated billings, a new deposit requirement may be calculated and an additional deposit may be required within two days. The deposit shall be refunded to residential Customers in the form of cash or credit to a customer's account when the Customer has paid 12 consecutive bills without having service disconnected for non-payment, and without having one or more occasion in which a bill was delinquent or a payment was returned, and the Customer is not currently delinquent.

10.2 RECEIPTS

The Company shall maintain such records as may be necessary to permit any Customer to receive any deposit return to which he or she is entitled without presentation of the receipt. A record of any unclaimed deposits shall be maintained by the Company for at least 4 years.

10.3 INTEREST

The Company shall pay interest on all security deposits for the time held at the rate as set by the Public Utility Commission annually except when

a) The deposit is held 30 days or less;
b) Notice is sent to the Customer's last known address that the deposit is no longer required;
c) The service to which the deposit relates has been discontinued; or
d) All or any part of the deposit has been applied to a delinquent account.

Interest on deposits earned during the preceding year shall be paid to the Customer annually. Payment shall be made either by check or as a credit on the monthly bill at the Company's option.

10.4 RETURN OF DEPOSITS

Deposits on residential accounts returned to the Customer in accordance with Section 10.1 above shall be applied in the first calendar quarter following the month in which the good payment record is established. Whenever the deposit of any Customer is returned to the Customer, the Company shall pay all previously unpaid interest with the payment.

10.5 ACCEPTABLE FORMS OF DEPOSIT

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

SECURITY DEPOSITS (Continued)

10.5 ACCEPTABLE FORMS OF DEPOSIT (Continued)

a) A cash deposit of as much as one-sixth (1/6) the estimated annual billings for service requested; but no less than the minimum deposit set forth in Section 21.2;

b) For commercial customers only, a nontransferable, irrevocable letter of credit from an established financial institution, payable for as much as one-sixth (1/6) the estimated annual billings for services requested and, which can be drawn on for a minimum of two (2) years; but no less than the minimum deposit set forth in Section 21.2; or

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

10.6 FRANCHISE AGREEMENTS

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

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

GAS MEASUREMENT

11.1 PRESSURE

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

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

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

11.2 UNIT OF MEASUREMENT

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

GAS MEASUREMENT (Continued)

11.2 UNIT OF MEASUREMENT (Continued)

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.

11.3 BILLING UNIT

Unless otherwise specified on the rate schedules or by special agreement, Customers shall be billed on the basis of Ccf measured at or corrected to the standard serving pressure. The index of the meter shall be the sole determinant of volumes passing through the meter. Whenever the meter reads directly in hundreds or smaller units, a reading of one-half a billing unit or more (500 Ccf or more) shall be considered a whole billing unit. Readings of less than one-half a unit shall be disregarded for billing. In those cases in which heating value is used as the billing unit, the calculation of the heating value in BTU's shall be made in accordance with Section 11.7 of this Tariff.

11.4 PRESSURE CORRECTION - STANDARD METERING

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

a) 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.

   The Company may use factor billing whenever the volumes to be delivered are too small to justify special metering. The factor shall be determined by dividing the actual serving pressure by the standard serving pressure, both expressed in absolute units based on the standard atmospheric pressure in the area as specified in Section 11.1 hereof. This factor shall be applied to the measured volumes to determine the correct number of billing units.

11.5 METERING - SPECIAL POSITIVE DISPLACEMENT

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

GAS MEASUREMENT (Continued)

11.5 METERING - SPECIAL POSITIVE DISPLACEMENT (Continued)

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 tests indicate significant changes in gravity, volume calculations shall be changed prospectively to reflect the new gravity.

11.6 METERING - SPECIAL ORIFICE

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

a) 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.

11.7 BTU MEASUREMENT

The heating value of gas for use in billing shall be defined as the gross thermal value of one cubic foot of gas at a pressure of 14.73 psia and temperature of 60 degrees Fahrenheit on a dry basis.

GAS MEASUREMENT (Continued)

11.7 BTU MEASUREMENT (Continued)

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.

11.8 CUSTOMER-OWNED METERS

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

METER READING AND ACCURACY

12.1 METER READING

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

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

If practical, an actual reading shall be made after two consecutive estimated bills. All meters in Special Service shall be read at least once a month. Whenever such a meter fails to register or is misread, the amount of gas used during the preceding period shall be estimated using data applicable to that Special Service Customer only. The Company will make a special reading of any meter upon request and payment of a service charge will be made in accordance with Section 21.1. The time of the special reading shall be agreed upon with the Customer so that he or she may be present. If the original reading was in error (subject to consumption between the two readings) the service charge will be refunded to the Customer.

12.2 ACCESS TO THE METER

The Customer shall permit the Company safe access to the meter at all reasonable times for reading thereof and at all reasonable times for reading, maintenance, testing, or replacement of the meter. Upon the Customer's failure or refusal to grant such access, the Company may issue a written notice to the Customer, advising them the situation must be corrected and access granted within 5 working days and that failure to do so can result in the disconnection of service and removal of the meter. Additional fees may apply and will be assessed to such Customer as specified in Section 21.1.

12.3 METER ACCURACY

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

12.4 METER TESTING AT CUSTOMER REQUESTS

The Company shall have the right to remove and/or test the meter used to determine the quantity of gas delivered. The Customer may request that the Company make a special test of the meter through which he or she is served. Requests for such tests shall be made in writing and the Company shall have 10 days after receipt of the request to remove the meter for testing or to test the meter in place. Tests on removed meters shall be conducted within a reasonable time. If the test is to be performed after the period of presumed accuracy listed by the manufacturer or if the test is to be performed for a residential or small commercial Customer for whom no such test has been performed within the previous four (4) years for the same Customer at the same location, no service charge will be assessed. Otherwise, the Customer shall pay a service charge for such test as specified in Section 21.1.

METER READING AND ACCURACY (Continued)

12.5 BILLING ADJUSTMENTS - GENERAL SERVICE

Whenever it has been determined that a meter reading and the subsequent billing has been in error, the Company shall recalculate the affected bill(s). If the date and amount of the error can be definitely fixed, the Company shall refund or may bill the affected Customer for the entire difference between the actual bills rendered and the amount which should have been billed. If a meter is found to have registered inaccurately (such as a meter found to be registering fast or slow), the Company shall refund or bill an amount equal to the difference between the actual bills rendered and the amount which would have been billed if the meter was 100 percent accurate during the time since the last previous test or six months, whichever is less. If the meter is found not to have registered, then the rebilling shall be limited to a three-month period previous to the time the meter is found not to be registering. The determination of amounts used but not metered is to be based on consumption during other like periods by the same Customer at the same location, when available, and on consumption under similar conditions at the same location or of other similarly situated Customers, when not available. Undercharges billed to the Customer may be repaid in a series of equal installments over a reasonable period of time. This Section shall not apply to meter errors found as a result of routine testing in the Company's or its designee's meter shop.

12.6 PROVISIONS FOR SPECIAL SERVICE

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

a) Orifice and turbine meters shall be tested at least four times per year at intervals not to exceed 120 days. Should the Customer so elect, tests shall be made in the presence of his or her representative.

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

   i) by using registration of Customer's check meter(s);

   ii) by correcting the error, if the percentage of error is ascertainable by calibration test or mathematical calculation; or

   iii) by estimating the quantity of gas delivered by comparison with deliveries during the preceding period under similar conditions when accurate registration was obtained.

12.7 PERIODIC TESTS

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

BILLING AND PAYMENT OF BILLS

13.1 RENDERING OF BILLS

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

13.2 BILLING PERIOD

Bills shall be rendered at regular monthly intervals unless otherwise authorized or unless service is rendered for a period of less than a month.

13.3 ESTIMATED BILLS

In the event any meter cannot be read at the end of the billing period, the Company shall bill the Customer on the basis of an estimated consumption determined in accordance with Section 12.1 of this Tariff. The next bill based on actual reading after an estimated bill shall make any corrections necessary to bring the Customer's account to a current status for the actual consumption.

13.4 DISPUTED BILLS

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

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

13.5 PAYMENT RE-PROCESSING FEE

The Company may charge or add to the Customer's account and collect a fee (as provided in Section 21.1 d) to recover costs for reprocessing any payment, including paper check, electronic transfer payment, and debit and credit card payment, that has been rejected or returned to the Company by the bank for any reason other than bank error.

BILLING AND PAYMENT OF BILLS (Continued)

13.6 E-STATEMENTS

The Customer may at its option receive bills and notices via electronic mail, thereby eliminating paper bills and notices.

13.7 PAYMENT OPTIONS

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

13.8 DEFERRED PAYMENT PLANS

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

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

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

 i) size of delinquent account;

 ii) Customer's ability to pay;

 iii) Customer's payment history;

 iv) time that the debt has been outstanding;

 v) reasons why debt has been outstanding; and

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

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

d) A deferred payment plan may include a one-time late payment penalty up to but no more than 5% of the original amount of the outstanding bill with no prompt payment discount allowed except in cases where the outstanding bill is unusually high as a result of the Company's error (such as an inaccurately estimated bill or an incorrectly read meter). A deferred payment plan shall not include a finance charge.

e) If a Customer has not fulfilled terms of a deferred payment agreement or refuses to sign the same if it is reduced to writing, the Company shall have the right to disconnect pursuant to disconnection rules in Section 17.2 of this Tariff and, under such circumstances, it shall not be required to offer a subsequent negotiation of a deferred payment agreement prior to disconnection.

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

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, providing that the average heating value for the calendar month in which the reduction occurs is equal to or greater than the standard and that the burning characteristics of the gas are not significantly altered.

14.2 CHARACTER OF GAS

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

14.3 ODORIZATION

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

SERVICE WORK

15.1 CERTAIN SERVICES PROVIDED AT NO CHARGE

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.

15.2 OTHER SERVICE

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 work and the associated revenues and costs shall be considered non-utility.

15.3 EXPEDITED SERVICE

A Customer may request an expedited service. Charges may apply. (See Section 21 – Fees and Deposits)

15.4 NO ACCESS

A fee may be charged to a Customer who requests a specific time for service, if the Company agrees to the time, sends appropriate personnel to the appointed location and the Customer is not present to allow access to the premises. (See Section 21 – Fees and Deposits)

15.5 MATERIALS OR EQUIPMENT FURNISHED BY THE COMPANY

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

15.6 MATERIALS OR EQUIPMENT FURNISHED BY THE APPLICANT

The Applicant shall furnish and install at his or her expense all piping, conversions of existing equipment, and appliances required to conduct and utilize the gas furnished by the Company. The adequacy, safety, and compliance with applicable codes and ordinances of piping, conversion equipment and appliances shall remain the responsibility of the Applicant and no action of the Company in accordance with this Tariff shall release the Applicant of the responsibility to furnish and install the facilities required by this Section.

SERVICE WORK (Continued)

15.7 CODES AND ORDINANCES

All piping, installations, and conversion equipment owned by the Applicant shall comply with all applicable federal, state, and city ordinances and shall be properly designed for the pressures and volumes to be handled. Where there are no appropriate ordinances, the applicable provisions of the National Fuels Gas Code 54; ANSI Z223.1, and any amendments thereto shall apply.

15.8 INSPECTIONS AND TESTS

The Company shall have the right to inspect new installations and/or conversions of appliances and equipment prior to initiation of service and to require any test or repair of the Applicant's facilities it deems necessary, at no charge to the customer.

15.9 REFUSAL TO SERVE

The Company shall refuse service to any Applicant who refuses Company or Company's representatives access to or entry for observation or whose facilities do not comply with the applicable provision of this Tariff. The right to refuse service shall terminate upon satisfactory correction of the condition that was the cause for refusal. Initiation of service, however, shall not be considered acceptance or approval by the Company of such facilities.

MAINTENANCE OF EQUIPMENT

16.1 MAINTENANCE BY COMPANY

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

16.2 MAINTENANCE BY THE CUSTOMER

The Customer shall maintain all facilities owned by him or her and shall be responsible for the safe conduct and handling of the gas after it passes the point of delivery. The Customer shall remove, repair or adjust any Customer-owned property which may pose a threat of damage to the property of the Company. The Customer shall take all reasonable means to assure that no one other than an employee of the Company shall adjust, repair, disconnect or change the meter or other Company facilities in any way. In case of loss or damage to the Company's property from the negligence or willful acts of the Customer or Consumer or the Customer's or Consumer's representatives, the Customer will reimburse the Company for all costs of repairing or replacing the damaged property, including any costs of collection such as attorney's fees.

16.3 LEAKS - RIGHT TO DISCONNECT FOR

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

16.4 FACILITIES CURRENTLY OWNED BY THE CUSTOMER

Any facilities downstream of the meter installed by the Customer shall remain the property and responsibility of the Customer. Whenever the condition of the facility is such that replacement is required, the work shall be done by the Company pursuant to the provisions of Section 16.7 of this Tariff. New facilities will continue to be installed pursuant to Sections 7.1 and 7.2 of this Tariff.

16.5 RESPONSIBILITY

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

MAINTENANCE OF EQUIPMENT (Continued)

16.6 RELOCATION OF COMPANY FACILITIES

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

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

16.7 REPLACEMENT OF CUSTOMER-OWNED PIPING

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

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

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

DISCONTINUANCE OF SERVICE

17.1 BY CUSTOMER

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

17.2 FOR NON-PAYMENT

The Company shall have the right to discontinue service to any Customer for non-payment of bills or other charges authorized by this Tariff or the applicable rate schedules, following the due date specified in Section 13.1 hereof. Before discontinuing service for non-payment, the Company shall mail a separate written notice to the Customer in English and Spanish with the words "TERMINATION NOTICE" or similar language prominently displayed. This notice shall include a telephone number to contact the Company, the amount of the delinquent bill and the date by which the bill must be paid to avoid disconnection, and a statement of how to contact the Company in case of illness or other emergency. If a representative of the Company makes an attempt to collect a past due amount, a collection fee per visit shall be assessed to such Customers as specified in Section 21.1.

No Customer shall be disconnected for non-payment:

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

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

c) Before 7:00 AM or after 7:00 PM on any day or on Friday, Saturday, Sunday, Holiday, or day before a holiday unless Company personnel are available the following day for the purpose of making collections or reconnecting service.

d) If within 5 working days after the date of delinquency of the bill the Company receives a written request from the Customer not to discontinue service for health reasons and the request is accompanied by a written statement from a licensed physician. Upon receipt of such request, the Company will suspend termination of service for a period up to 20 days. The Customer shall sign a deferred payment plan agreement which provides for payment of such service along with timely payments for subsequent monthly billings.

17.3 EXTREME WEATHER EMERGENCY

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

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

DISCONTINUANCE OF SERVICE (Continued)

17.3 EXTREME WEATHER EMERGENCY (Continued)

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

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

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

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

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

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

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

17.4 SPECIAL CONDITIONS

The Company shall have the right to discontinue service to any Consumer for any of the following reasons:

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

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

c) Within 5 working days after written notice if the Consumer uses his or her equipment in any way which causes or creates a potential for adverse affect on the Company's service to others;

d) Without notice if failure to curtail by such Consumer endangers the supply to Consumers in Priority Class A or B;

DISCONTINUANCE OF SERVICE (Continued)

17.4 SPECIAL CONDITIONS (Continued)

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

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

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

h) If a Customer fails to uphold the terms of a deferred payment plan; or

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

17.5 RIGHT OF ENTRY

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

17.6 ABANDONMENT OF SERVICE

Unless requested by the Customer, service shall not be abandoned (permanent disconnection of any Customer other than a temporary Customer) without permission of the Regulatory Authority. Failure of the Customer to request reinstitution of service within a reasonable period of time after disconnection shall be considered a request for permanent discontinuance of service.

RE-ESTABLISHMENT OF SERVICE

18.1 FOR NON-PAYMENT

When service has been disconnected for non-payment, the Company shall require that the Customer pay the total amount of his or her account then due plus the prescribed reconnect fee or make satisfactory arrangements for that payment before service is reinstituted. In addition, the Company shall require that the Customer re-establish satisfactory credit in accordance with Section 5 of this Tariff.

18.2 FOR OTHER REASONS

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

18.3 RECONNECTION

The Company shall restore service as soon as feasible after receipt of a reconnection request and compliance with the requirements of this Section. The Company shall charge a non-refundable reconnection fee for all Customers in accordance with Section 21.1. The restoration of service will be accomplished as expeditiously as scheduling permits. If the Customer requests service after hours or earlier than reconnection would otherwise be scheduled, the Company shall offer expedited service in accordance with Section 21.1. Customer shall be advised that an additional fee will be charged and must agree to pay such charge. In the event the Company is required to make more than one call because the reason for disconnection has not been properly corrected, the reconnect fee may be charged for each call made. No fee shall be charged for any reconnection made after disconnection due to Company's operation. See Section 21.1 for fees.

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

NOTICE

19.1 GENERAL

Notice is required for all matters in this Tariff other than billing and payment of bills, which shall be deemed to have been given by the Customer when a letter with postage prepaid has been deposited in the United States Mail addressed to the Company at the office specified on the front sheet of this Tariff, and to the Customer when addressed to Customer at his or her last known service address, or to either party when directly communicated to the other party in person or by telephone.

AVERAGE BILL CALCULATION PLAN or AVERAGE PAYMENT PLAN

20.1 DESCRIPTION-RESIDENTIAL

Any residential Customer may elect to participate in the Company's Average Payment Plan, also known as the Average Bill Calculation Plan ("ABC/APP Plan"), or as such ABC/APP Plan may be modified from time to time for payment of charges for gas service. In the event the Company modifies the ABC/APP Plan, the Company shall notify individual Customers of those changes when the Customer requests enrollment. In general, the conditions under which a Customer may participate in the ABC/APP Plan are set forth below:

a) The Company reserves the right to adjust the monthly ABC/APP Plan payments of any Customer at any time for changes in conditions or rates;

b) The Company shall advise each Customer in the ABC/APP Plan of the monthly ABC/APP Plan payment to be paid by the Customer. Each participating Customer will receive a regular monthly gas bill which will reflect actual consumption and charges for that billing month and the amount of any debit or credit balance before the payment of that month's ABC/APP Plan payment. The Customer shall continue to pay the monthly ABC/APP Plan payment amount each month for gas service, notwithstanding the current gas service charge shown on the bill;

c) In addition to the monthly ABC/APP Plan amount, any other charges incurred by the Customer shall be paid monthly when due;

d) Interest shall neither be charged to the Customer on accrued ABC/APP Plan debit balances nor paid by the Company on accrued ABC/APP Plan credit balances;

e) Any amount due the Customer or the Company will be settled and paid at the time a Customer, for any reason, ceases to be a participant in the ABC/APP Plan;

f) Any Customer's participation in the ABC/APP Plan may be discontinued by the Company if the monthly plan payment has not been paid on or before the due date of the monthly plan payment;

g) If any Customer in the ABC/APP Plan shall cease, for any reason, to participate in the ABC/APP Plan, then the Company may deny that Customer's reentry into the ABC/APP Plan until the following year.

FEES AND DEPOSITS

21.1 FEES

All fees and charges shall be adjusted by taxes and fees (including franchise fees) where applicable. In the incorporated areas of Bayou Vista, Cuero, Galveston, Gonzales, Groves, Jamaica Beach, Lockhart, Luling, Nederland, Nixon, Port Arthur, Shiner and Yoakum only, all fees and charges (excluding advances, contributions in aid of construction and deposits) shall be adjusted by the amount which represents the actual gross receipts, occupation, revenue taxes and franchise fees paid by Texas Gas Service Company, a Division of ONE Gas, Inc.

a) Initiation of Service:

i) Connect: (Section 5.4) $35.00

A connection fee shall be charged to any Applicant for the cost involved in initiation of service. This fee shall be charged when a meter is set and/or gas turned on.

ii) Read-In: (Section 5.4) $15.00

A read-in fee shall be charged to any Applicant for the cost involved in initiation of service. This fee shall be charged when only a meter reading is required.

iii) Special Handling & Expedited Service: (Sections 5.4 and 15.3)

In addition to initiation of service fee above, a fee may be charged to any Applicant whose request to initiate service cannot be worked during normal business hours or requires special handling. Applicant must be advised that an additional fee will be charged and must agree to pay such charge. These charges include:

1) Special Handling $15.00

The Company may, at Applicant or Customer's request, provide special handling in order to meet the Applicant or Customer's requirements. Special handling does not include calling the Applicant/Customer in advance or A.M. or P.M. scheduling

2) Expedited Service and Overtime Rate $60.00

The Applicant or Customer's request for expedited service may be scheduled at any time to fit the Company's work schedule, and an Expedited Service charge shall be collected. The Company shall not be obligated to provide Expedited Service when the personnel and resources to do so are not reasonably available.

b) Services - Others As stated below

Whenever service is furnished from the facilities of others and the Company must pay any special fees to the supplying Company, the Applicant may be requested to reimburse the Company for such charge.

FEES AND DEPOSITS (Continued)

21.1 FEES (Continued)

c) Customer Requested Meter Test: (Section 12.4)

Positive Displacement	Charge
Up to 1500 cubic feet per hour	$150.00
Over 1500 cubic feet per hour	$200.00
Orifice Meters	
All sizes	$200.00

d) Payment Re-processing Fee: (Section 13.5) $25.00

e) Collection Fee: (Section 17.2) $15.00

A Collection Fee shall be charged to any Customer whose failure to respond to a termination notice necessitates the dispatch of a Company representative to attempt collection of payment from Customer.

f) Reconnect Fees: (Section 18.3) $35.00

A reconnect fee shall be charged to any Customer whose service is terminated and then re-initiated unless terminated in error by the Company. This fee is the same as the Standard Initiation Fee charged for new service.

(i) Regular Labor and After Hours Rates $45.00 (Regular)
$60.00 (After Hours)

Charge for non-routine services including but not limited to repeat high bill investigations and building meter loops.

g) Special Read: (Section 12.1) $15.00

A special read fee shall be charged for customer requested reading of a meter of which estimated billing has been made. This is not in connection with Section 12.4.

h) Meter Exchange (Customer Request): (Section 16.6) $150.00

A fee will be charged for customers requested meter exchanges when a meter is working properly or is done for the customer's convenience.

FEES AND DEPOSITS (Continued)

21.1 FEES (Continued)

i) Meter Tampering – Residential: (Section 16.2) $150.00

A fee will be charged to repeat customers who knowingly tamper with Company property (i.e. broken meter locks, broken stop cocks, tampered meter dials, and broken meter blind seals).

j) Unauthorized Consumption: (Section 16.2) $30 plus expenses

Charges for the replacement of an illegally broken meter seal or locking device to the Customer who could be reasonably expected to benefit from gas service received through said meter.

k) No Access Fee: (Section 15.4) $15.00

A fee charged to a Customer who schedules an appointment but fails to appear.

l) Meter Removal Fee: (Section 12.2) $25.00

m) Account Research Fee: $20.00/hr

A fee will be charged for Customer account information requiring research of accounting/billing information.

n) Police Escort Fee: (Section 17.4) As stated below

A fee charged when the Company is required to use law enforcement personnel to escort it into locked sites or sites requiring animal control in order for the Company to access a meter. Company will charge the stated amounts or current rate charged by the entity providing the police escort for this service.

o) Excess Flow Valve Installation Fee: $400.00

Pursuant to Code of Federal Regulations, §192.383(d) a fee for installation of an excess flow valve (EFV) will be assessed when a Customer requests such installation on the Customer's service line. The EFV will be installed at a date mutually agreeable to both Company and Customer, but after January 1, 2018. The Company reserves the sole right to conduct any required maintenance that may result from the installation. The customer shall be assessed a one-time installation fee.

FEES AND DEPOSITS (Continued)

21.2 DEPOSITS

a) Advances: (Section 8.4) As stated below

Estimated expenditure to serve the premises of new business beyond the existing distribution facilities of the Company.

b) Customer Deposits: (Section 10.1) As stated below

Minimum deposit residential:	$75.00
Minimum non residential deposit:	$250.00

Texas Gas Service Company, a Division of ONE Gas, Inc.
CGSA ISOS RTCS TYE June 30, 2019
Updated for Known and Measurable Changes Through September 30, 2019

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Exhibit B
Proposed CGSA Revenue Change by Class

					Recommended Rates						
Line No.	Description	Bills	Units	Volumes	Customer Charge	Usage Charges	Recommended Revenue	Assigned Revenue	Rounding Diff.	Test Year As Adjusted Revenue	Revenue Change
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Residential - Rate Option A										
2	Incorporated	1,805,218	All Ccf	31,181,461	$14.00	$0.55702	$42,641,754	$49,893,225	($7,251,471)	$35,198,539	$14,694,686
3	Environs	156,059		4,108,022			4,473,076	4,318,065	155,011	3,692,291	625,774
4		1,961,277		35,289,483			$47,114,831	$54,211,290	($7,096,459)	$38,890,830	$15,320,460
5											
6	Residential - Rate Option B										
7	Incorporated	1,442,030	All Ccf	62,124,484	$27.58	$0.10435	$46,253,866	$39,983,201	$6,270,666	$38,180,149	$1,803,052
8	Environs	124,662		8,184,630			4,292,238	3,466,172	826,065	3,543,018	(76,846)
9		1,566,691		70,309,113			$50,546,104	$43,449,373	$7,096,731	$41,723,167	$1,726,206
10											
11	Total Residential										
12	Incorporated	3,247,248		93,305,945			$88,895,621	$89,876,426	($980,805)	$73,798,612	$16,077,814
13	Environs	280,721		12,292,651			8,765,314	7,784,237	981,077	6,815,385	968,852
14	**Total Residential**	**3,527,969**		**105,598,596**			**$97,660,935**	**$97,660,663**	**$272**	**$80,613,997**	**$17,046,666**
15	Commercial										
16	Incorporated	161,301	All Ccf	42,406,738	$53.33	$0.12678	13,978,523	13,978,573	(50)	13,979,227	(654)
17	Environs	8,139		2,086,881			698,609	698,611	(3)	679,206	19,406
18		169,440		44,493,619			14,677,132	14,677,185	(53)	14,658,433	18,752
19											
20	Commercial Transportation										
21	Incorporated	4,278	All Ccf	20,037,683	$265.33	$0.12678	$3,675,506	$3,675,520	($13)	$3,623,164	$52,356
22	Environs	107		203,043			54,120	54,121	(0)	125,228	(71,108)
23		4,385		20,240,726			$3,729,627	$3,729,640	($13)	$3,748,392	($18,752)
24											
25	Total Commercial										
26	Incorporated	165,579		62,444,421			$17,654,030	$17,654,093	($63)	$17,602,391	$51,702
27	Environs	8,246		2,289,925			752,729	752,732	(3)	804,434	(51,702)
28	**Total Commercial**	**173,825**		**64,734,346**			**$18,406,759**	**$18,406,825**	**($66)**	**$18,406,825**	**$0**
29	Industrial										
30	Incorporated	256	All Ccf	656,316	$320.96	$0.12703	$165,509	$165,511	($2)	$148,125	$17,386
31	Environs	-		-			0	0	0	1,642	(1,642)
32		256		656,316			$165,509	$165,511	($2)	$149,767	$15,744
33											
34	Industrial Transportation										
35	Incorporated	431	All Ccf	6,241,707	$520.96	$0.12703	$1,017,658	$1,017,673	($14)	$1,042,467	($24,795)
36	Environs	13		276,726			41,684	41,685	(1)	32,634	9,051
37		444		6,518,433			$1,059,343	$1,059,358	($15)	$1,075,101	($15,744)
38	Total Industrial										
39	Incorporated	687		6,898,023			$1,183,167	$1,183,184	($17)	$1,190,592	($7,409)
40	Environs	13		276,726			41,684	41,685	(1)	34,276	7,409
41	**Total Industrial**	**700**		**7,174,749**			**$1,224,851**	**$1,224,869**	**($17)**	**$1,224,869**	**$0**

Texas Gas Service Company, a Division of ONE Gas, Inc.
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Exhibit B
Proposed CGSA Revenue Change by Class

Line No.	Description	Bills	Units	Volumes	Recommended Rates Customer Charge	Usage Charges	Recommended Revenue	Assigned Revenue	Rounding Diff.	Test Year As Adjusted Revenue	Revenue Change
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
42	Public Authority										
43	Incorporated	9,355	All Ccf	3,680,792	$81.70	$0.12551	$1,226,256	$1,226,274	($18)	$1,310,261	($83,987)
44	Environs	616		728,392			141,765	141,767	(2)	128,638	13,129
45		9,971		4,409,183			$1,368,021	$1,368,041	($20)	$1,438,899	($70,858)
46											
47	Public Authority Transportation										
48	Incorporated	4,607	All Ccf	7,359,059	$104.70	$0.12551	$1,405,967	$1,405,988	($21)	$1,325,432	$80,555
49	Environs	74		38,041			12,544	12,544	(0)	18,491	(5,947)
50		4,681		7,397,100			$1,418,511	$1,418,532	($21)	$1,343,924	$74,608
51											
52	Public School Space Heating										
53	Incorporated	51	All Ccf	36,885	$134.70	$0.10012	$10,569	$10,569	($0)	$10,602	($33)
54	Environs	14		87,719			10,616	10,616	(0)	10,583	33
55		65		124,603			$21,185	$21,185	($0)	$21,185	$0
56											
57	Public School Space Heating Transportation										
58	Incorporated	957	All Ccf	1,192,956	$234.70	$0.10012	$343,990	$343,995	($5)	$347,577	($3,582)
59	Environs	23		7,199			6,175	6,175	(0)	6,344	(168)
60		980		1,200,155			$350,165	$350,171	($5)	$353,921	($3,750)
61											
62	Electrical Cogeneration Transportation										
63	Incorporated	12	First 5000	60,000	$104.70	$0.07720	$5,888	$5,888	$0	$5,888	$0
64			Next 35,000	420,000		$0.06850	28,770	28,770	0	28,770	0
65			Next 60,000	720,000		$0.05524	39,773	39,773	0	39,773	0
66			Over 100,000	2,685,983		$0.04016	107,869	107,869	0	107,869	0
67	Incorporated	12		3,885,983			$182,300	$182,300	$0	$182,300	$0
68											
76	Total Public Authority										
77	Incorporated	14,981		16,155,674			$3,169,082	$3,169,126	($44)	$3,176,173	($7,047)
78	Environs	727		861,349			171,100	171,103	(3)	164,056	7,047
79	**Total Public Authority**	**15,709**		**17,017,024**			**$3,340,182**	**$3,340,229**	**($47)**	**$3,340,229**	**$0**
80	Compressed Nat. Gas										
81	Incorporated	36	All Ccf	620	$192.63	$0.06684	$6,976	$6,976	($0)	$6,976	$0
82	Environs	-		-			0	0	0	0	0
83		36		620			$6,976	$6,976	($0)	$6,976	($0)
84											
85	Compressed Nat. Gas Transportation										
86	Incorporated	36	All Ccf	933,999	$217.63	$0.06684	$70,263	$70,263	($0)	$70,263	($0)
87	Environs	12		418,088			30,557	30,557	(0)	30,557	0
88		48		1,352,087			$100,820	$100,820	($0)	$100,820	$0
89											
90	Total Compressed Nat. Gas										
91	Incorporated	72		934,619			$77,239	$77,239	($0)	$77,239	$0
92	Environs	12		418,088			30,557	30,557	(0)	30,557	0
93	**Total Compressed Nat. Gas**	**84**		**1,352,707**			**$107,796**	**$107,796**	**($0)**	**$107,796**	**$0**

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 CGSA Revenue									
95	Incorporated	$110,979,139	$111,960,068	($980,929)	$95,425,084	$16,534,984	$4,596,650	$64,614,605	16.53%	10.04%
96	Environs	9,761,384	8,780,313	981,071	8,268,631	511,682	713,842	7,095,145	5.70%	3.18%
97	Total Revenue	$120,740,523	$120,740,381	$142	$103,693,715	$17,046,666	$5,310,492	$71,709,750	15.64%	9.43%

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 - Rate Option A				
CTSA Incorporated	$29.20	$32.33	$3.13	10.7%
CTSA Environs	$29.20	$32.33	$3.13	10.7%
GCSA Incorporated	$29.57	$32.33	$2.76	9.3%
GCSA Environs	$30.44	$32.33	$1.89	6.2%
Beaumont Incorporated	$29.25	$32.33	$3.08	10.5%
Residential - Rate Option B				
CTSA Incorporated	$44.71	$52.99	$8.28	18.5%
CTSA Environs	$44.71	$52.99	$8.28	18.5%
GCSA Incorporated	$55.21	$52.99	($2.22)	-4.0%
GCSA Environs	$54.74	$52.99	($1.75)	-3.2%
Beaumont Incorporated	$54.89	$52.99	($1.90)	-3.5%
Commercial				
CTSA Incorporated	$203.72	$207.89	$4.17	2.0%
CTSA Environs	$203.72	$207.89	$4.17	2.0%
GCSA Incorporated	$239.47	$207.89	($31.58)	-13.2%
GCSA Environs	$243.14	$207.89	($35.25)	-14.5%
Beaumont Incorporated	$237.85	$207.89	($29.96)	-12.6%
Industrial				
CTSA Incorporated and Environs	$1,755.39	$1,831.10	$75.71	4.3%
Public Authority				
CTSA Incorporated and Environs	$334.64	$341.41	$6.77	2.0%
GCSA Incorporated	$390.32	$341.41	($48.91)	-12.5%
GCSA Environs	$392.78	$341.41	($51.37)	-13.1%
Public Schools Space Heating				
CTSA Incorporated and Environs	$1,207.53	$1,217.59	$10.06	0.8%
Compressed Natural Gas				
CTSA Incorporated	$201.64	$201.73	$0.09	0.0%
Transportation Service: (3)				
Commercial Transportation				
CTSA Incorporated	$2,803.50	$2,875.50	$72.00	2.6%
CTSA Environs	$2,803.50	$2,875.50	$72.00	2.6%
GCSA Incorporated	$3,378.83	$2,875.50	($503.33)	-14.9%
Industrial Transportation				
CTSA Incorporated and Environs	$8,397.14	$8,826.68	$429.54	5.1%
GCSA Incorporated	$12,693.43	$8,826.68	($3,866.75)	-30.5%
Public Authority Transportation				
CTSA Incorporated and Environs	$972.51	$996.30	$23.79	2.4%
Public School Space Heating Transportation				
CTSA Incorporated and Environs	$888.51	$894.58	$6.07	0.7%
Cogeneration Transportation (4)				
CTSA Incorporated	$155,654.46	$157,260.17	$1,605.71	1.0%
Compressed Natural Gas Transportation				
CTSA Incorporated and Environs	$14,318.55	$14,458.22	$139.67	1.0%

(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 and do not include the Conservation Adjustment Clause rate, which is applicable in the incorporated CTSA. Taxes vary across different locations in the service area.

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

	Proposed CGSA	
	Year-Round	January
Residential - Rate Option A	18	48
Residential - Rate Option B	45	121
Commercial	263	441
Industrial	2,565	5,228
Public Authority	442	1,002
Public School Space Heating	1,927	2,295
Compressed Natural Gas	17	30

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

	Proposed CGSA	
	Year-Round	January
Commercial Transportation	4,616	5,730
Industrial Transportation	14,681	16,571
Public Authority Transportation	1,580	2,328
Public School Space Heating Transportation	1,225	2,191
Compressed Natural Gas Transportation	28,168	26,196

	Proposed CGSA	
	August	January
Cogeneration Transportation	339,785	323,832

(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.

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

G. DAVID SCALF

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF G. DAVID SCALF

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is G. David Scalf. My business address is 15 E. 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 Vice President of Rates and Regulatory Affairs. In this role, I am responsible for the rates and regulatory activities of ONE Gas' three natural gas distribution utilities – Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service Company ("TGS" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I am a Certified Public Accountant with a Bachelor of Science Degree in Finance. I practiced in public accounting for ten years and for approximately nine years, I worked in various positions within the Public Utility Division of the Oklahoma Corporation Commission. In August 2003, I joined Oklahoma Natural Gas as a Regulatory Analyst. I served in various roles at Oklahoma Natural Gas, including Manager of Financial Accounting, Manager of Contract Administration and Director of Rates and Regulatory. I assumed my current position with ONE Gas in October 2016.

Q. HOW DOES YOUR BACKGROUND AND EXPERIENCE PROVIDE INSIGHT ON ISSUES RAISED IN THE COMPANY'S STATEMENT OF INTENT?

A. My career in public utility regulation and the natural gas distribution business has spanned over 20 years. During that time, I have been extensively involved with numerous aspects of regulatory filings that include: preparation of all aspects of general rate case applications; review of work papers and testimony of all witnesses participating in rate cases; interfacing with regulatory commission staff and all stakeholder groups including public advocacy and industry groups; and compliance with regulatory statutes and requirements. I have testified before the Oklahoma Corporation Commission numerous times regarding rate base, expenses, accounting, and regulatory policy issues. During my employment at the Oklahoma Corporation Commission, I participated in numerous audits of general rate cases filed by various natural gas, electric, and water utilities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AUTHORITIES IN TEXAS?

A. Yes, I provided pre-filed testimony in the Rio Grande Valley Service Area municipal level statement of intent filed in June 2017.

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 introduces TGS's Statement of Intent filing and the witnesses, in addition to myself, who are also filing testimony on behalf of the Company. I provide an overview of ONE Gas and the Company's request to consolidate its existing Central Texas Service Area ("CTSA"), Gulf Coast Service Area ("GCSA") and the City of Beaumont into a new Central-Gulf Service Area ("CGSA"). Finally, I address two adjustments in Schedule G from a management perspective: (1) incentive compensation and (2) meal and hotel costs. Other Company witnesses, which I identify below, also address these two subjects in testimony.

II. <u>OVERVIEW OF TGS'S STATEMENT OF INTENT FILING</u>

Q. PLEASE PROVIDE AN OVERVIEW OF ONE GAS.

A. ONE Gas is in its sixth year as a stand-alone, fully regulated natural gas utility trading on the New York Stock Exchange under the symbol "OGS." Headquartered in Tulsa, Oklahoma, ONE Gas operates as an independent natural gas distribution company focusing on delivering natural gas safely and reliably to customers in three states - Oklahoma, Kansas and Texas. ONE Gas has 3,614 employees, 878 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. WHY IS TGS FILING A STATEMENT OF INTENT AT THIS TIME?

A. Following ONE Gas' separation from ONEOK, Inc. in January 2014, TGS filed a rate case in each of its service areas, including three rate cases in which separate services areas were consolidated. Those statements of intent, filed between 2015 and 2018, 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. This Statement of Intent provides an opportunity for TGS to continue its efforts to achieve additional efficiencies through further service area consolidation and to request rates that more accurately reflect the current and expected costs of providing service in the proposed CGSA at the time new rates will go into effect.

Q. WHAT TEST YEAR WAS UTILIZED IN THIS FILING?

A. The Company's Statement of Intent filing is based on the financial results for the test year ended June 30, 2019, as adjusted for known and measurable changes through September 30, 2019.[1]

Q. WHY IS TGS REQUESTING A RATE INCREASE IN THIS STATEMENT OF INTENT?

A. In terms of revenue requirement, the Company's cost of service schedules show that TGS is experiencing a revenue deficiency primarily driven by plant investment and related depreciation expense, payroll-related expenses, and increasing regulatory and safety requirements. TGS has continued to invest in system safety and reliability, resulting in an increase of over $160 million in net plant. In addition, TGS must continue to invest in its employees and has experienced increases in 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 continue to increase. The costs associated with these requirements include operating expenses for activities such as leak repair, leak

[1] As Company witnesses Gracie Guerra and Mindy R. Edwards explain, TGS included September 30, 2019 Construction Work in Progress balances as an adjustment to construction completed not classified ("CCNC"). TGS will true-up net plant after December 31, 2019 to exclude any plant that is not used and useful at that time and will provide updated plant in service amounts, CCNC and accumulated reserves balances, along with related updated accumulated deferred income taxes and revenue growth, by February 14, 2020.

survey, and distribution integrity management. TGS also made additional capital investments in its natural gas distribution system that included investments due to government relocations and 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, more stringent 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 an opportunity to earn a reasonable return on its investment. The overall increase in the cost of service is partially offset by a reduction in the Federal income tax rate to 21% from 35%.

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 incented to reasonably manage its costs so that the Company will remain competitive and customers will 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.

Q. PLEASE PROVIDE EXAMPLES OF THE COMPANY'S IMPROVEMENTS IN CUSTOMER SERVICE ACTIVITIES.

A. Examples of improved customer service activities are:

(1) Electronic Statement Growth - Approximately one-third of ONE Gas customers receive electronic statements, which results in a savings in postage and materials;

(2) Enhanced Customer Communications - proactively putting information in customers' hands such as improved phone application and website, new text and e-mail campaigns for billing, payment reminders, and account updates to reduce the need for customer calls and potentially reduce disconnect orders;

(3) 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; and

(4) 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.

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

Q. PLEASE GENERALLY DESCRIBE THE RELIEF REQUESTED IN THIS STATEMENT OF INTENT.

A. The Company's cost of service demonstrates a total annual net revenue deficiency of $17,046,666 for the proposed CGSA. The Company proposes to eliminate this annual earnings deficiency and to have its rates set at a level that provides TGS a return on equity of 10.0%. 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 Statement of Intent, TGS is also seeking approval to consolidate the GCSA, CTSA and the City of Beaumont into a single, new service area known as the Central-Gulf Service Area. If consolidation and creation of the CGSA is not approved, TGS requests, at a minimum, that the City of Beaumont be consolidated into the GCSA. In addition, TGS is requesting a prudence determination for the capital investment made since the last CTSA and GCSA rate cases. Finally, TGS is also seeking a determination that ONE Gas' acquisition of ONEOK Transmission Company ("OTC") and its related assets is consistent with the public interest under Gas Utility Regulatory Act ("GURA") § 102.051.

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

A. The proposed rate increase will result in an increase to the average monthly bill for the 270,604 residential customers in the incorporated areas of the proposed CGSA and the 23,393 residential customers in the environs areas of the proposed CGSA, as shown in the table below.[2]

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

Line No.	Description	Current	Recommended	Change Dollars	Change %
	(a)	(b)	(c)	(d)	(e)
1	**Residential - Rate Option A**				
2	CTSA Incorporated	$29.20	$32.33	$3.13	10.7%
3	CTSA Environs	$29.20	$32.33	$3.13	10.7%
4	GCSA Incorporated	$29.57	$32.33	$2.76	9.3%
5	GCSA Environs	$30.44	$32.33	$1.89	6.2%
6	City of Beaumont	$29.25	$32.33	$3.08	10.5%
7	**Residential - Rate Option B**				
8	CTSA Incorporated	$44.71	$52.99	$8.28	18.5%
9	CTSA Environs	$44.71	$52.99	$8.28	18.5%
10	GCSA Incorporated	$55.21	$52.99	-$2.22	-4.0%
11	GCSA Environs	$54.74	$52.99	-$1.75	-3.2%
12	City of Beaumont	$54.89	$52.99	-$1.90	-3.5%

The proposed rates for all rate classes are identified in the direct testimony of Company witness Paul H. Raab and are reflected in the tariffs sponsored by Company witness Christy M. Bell. In addition to proposed gas sales, transportation, and cost of gas tariffs, the Company's filing includes other tariff and rate schedules such as a weather normalization clause, a rate case expense recovery rider, a pipeline integrity testing expense rider, and an excess deferred taxes rider. The Company is also proposing a Hurricane Harvey rider to recover response costs associated with the 2017 hurricane, and a Natural Event Response Rider that addresses the treatment of future natural event response costs. In addition, the Company proposes revised service fees and updated language in its transportation tariffs and rules of service.

Q. PLEASE IDENTIFY THE ISSUES OF FIRST IMPRESSION IN THIS STATEMENT OF INTENT.

A. The issues of first impression are related to recovery of: (1) compensation and benefit costs under a new statute, GURA § 104.060, which is addressed in my testimony and by Company witnesses Jeff D. Branz and Stacey R. Borgstadt; and (2) meal costs of $25 per person per meal, exclusive of taxes and tip amounts, and some hotel costs over $150 per night, exclusive of taxes, which is addressed in my testimony and that of Company witness Allison N. Edwards. In addition, the Company is proposing new residential A/B rate design options that are structured to allow customers some choice in how their customer charge and usage rates are structured based on their individual usage characteristics, as explained by Mr. Raab.

Q. PLEASE DESCRIBE THE COMPANY'S A/B RATE DESIGN PROPOSAL.

A. The Company is proposing two residential rates. Rate Option A benefits customers with lower than average usage. It includes a lower monthly customer charge of $14.00 but a higher volumetric rate of $0.55701 per Ccf. Rate Option B benefits residential customers with higher than average usage. It includes a $27.58 monthly customer charge but a much lower volumetric rate of $0.10434 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. 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, Rate Option B, which has a higher customer charge but lower volumetric charge, helps to levelize monthly charges for higher-use customers throughout the year.

If the proposed residential rate design is approved, the Company will initially place customers on the appropriate rate for the customer based on each customer's usage from the prior year. Subsequently, the customer will have the option to choose either Rate Option A or Rate Option B based on their own preference, provided that they remain on the rate they choose for a full year. The Company is excited to introduce an innovative new rate design in Texas that will allow customers some amount of choice in how they are billed for gas service.

Q. HAS A SIMILAR A/B RATE DESIGN BEEN PUT IN PLACE IN OTHER ONE GAS JURISDICTIONS?

A. Yes. The A/B rate design has been successfully implemented in ONE Gas' Oklahoma division, Oklahoma Natural Gas, and has been in place for fifteen years.

Q. HAS THE COMPANY INCLUDED REQUESTS RELATED TO FILINGS TGS PREVIOUSLY MADE WITH REGULATORY AUTHORITIES?

A. Yes, it has. TGS is requesting recovery of necessary costs it incurred to restore service following Hurricane Harvey in 2017, consistent with a settlement agreement the City of Galveston approved in July 2019 and the Railroad Commission of Texas ("Commission") approved in October 2019.[3] Company

[3] City of Galveston Ordinance 19-040; *Statement of Intent of Texas Gas Service Company a Division of ONE Gas, Inc., to Increase Rates to Recover Hurricane Harvey Response Costs Within the Gulf Coast Service Area*, GUD No. 10844, Final Order (Oct. 1, 2019). The Commission's order reflects it was exercising

witness Stacey L. McTaggart addresses the Hurricane Harvey costs in her testimony and the related request for approval of a Natural Event Response Rider that is designed to address deferral and recovery of costs associated with future storm or natural disaster events that may occur in the proposed CGSA.

TGS is also requesting a finding from the Commission that ONE Gas' June 2019 acquisition of OTC and its assets is consistent with the public interest. Company witness Shantel Norman discusses the purchase of these assets as they relate to the Company's operations. Ms. McTaggart addresses the Company's notification to the Commission of this transaction as required by GURA Section 102.051[4] and supports the request for a finding that the acquisition of OTC, now ONE Gas Pipeline Company ("OPC"), and its assets is consistent with the public interest. Ms. McTaggart also explains TGS's plan to incorporate the OPC assets into its existing system. Relatedly, several additional Company witnesses address necessary adjustments to the test year cost of service to support incorporating the OPC assets into the existing TGS system.

Q. PLEASE IDENTIFY THE WITNESSES SUBMITTING TESTIMONY IN THIS FILING 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 GDS-1 is a copy of the Table of Contents Summary to the CGSA Cost of Service schedules, which lists all the schedules and workpapers in this filing, along with the sponsor(s).

original jurisdiction over environs areas and appellate jurisdiction over the areas within the cities of Groves, Nederland, Port Arthur and Port Neches, Texas, all of which supported the settlement agreement.

[4] *Application filed by ONE Gas, Inc. to Report an Acquisition from ONEOK Transmission Company L.L.C.*, GUD No. 10877 (July 18, 2019).

Witness	**Title**	**Testimony Subjects**
Shantel Norman	Vice-President of Operations for TGS	Provides an overview of operations within the proposed CGSA; supports the proposed consolidation to create the CGSA; addresses the reasonableness and necessity of capital investment and Operations and Maintenance (“O&M”) expenses; addresses ONE Gas’ recent acquisition of OTC and the planned integration of the associated pipeline into TGS’s system; and addresses the Company’s Pipeline Integrity Testing Program.
Stacey L. McTaggart	Rates and Regulatory Director for TGS	Addresses the proposed consolidation of the existing CTSA, GCSA and City of Beaumont into the new Central-Gulf Service Area; the request for a finding that ONE Gas’ acquisition of the former OTC assets in June 2019, now held by OPC, is consistent with the public interest; the transfer of the OPC assets into TGS’s existing system; the Company’s compliance with certain regulatory and statutory requirements; affiliate cost recovery issues related to Utility Insurance Company (“UIC”) and OPC; the Company’s compliance with the Accounting Order issued by the Commission in Gas Utilities Docket (“GUD”) No. 10695 related to the federal Tax Cut and Jobs Act of 2017 (the “Act”); the Company’s proposed EDIT Rider to return excess deferred income taxes to customers; the proposed treatment of cloud-based computing costs in future filings; TGS’s recovery of costs associated with the Company’s response to Hurricane Harvey; the Company’s recovery of pipeline integrity testing costs; the proposed Natural Events Response Rider; and the Company’s recovery of rate case expenses.
Janet L. Buchanan	Director of Rates and Regulatory Reporting for Kansas Gas Service	Supports TGS’s revenue adjustments.
Gracie Guerra	Rates Analyst for TGS	Provides an overview of the cost of service and overall revenue requirement calculation and supports TGS’s Direct rate base.
Mindy R. Edwards	Rates Analyst for ONE Gas	Supports certain TGS Division and Corporate capital investment that is included in the proposed CGSA revenue requirement as well as Corporate depreciation and amortization expense.
Marie J. Michels	Manager of Rates and Regulatory Analysis for TGS	Supports Direct expense adjustments including an adjustment for O&M expenses related to the operation of the OPC pipeline, among others adjustments.

Anthony Brown	Rates Specialist for TGS	Supports the cost allocation methodology used to determine TGS's share of allocated costs and certain Corporate expense adjustments.
Allison N. Edwards	Manager of Rates and Regulatory Analysis for ONE Gas	Supports adjustments related to meal and hotel costs.
Stacey R. Borgstadt	Manager Rates and Regulatory Analysis for ONE Gas	Explains Direct, TGS Division and Corporate expense adjustments related to payroll and incentive compensation.
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.
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.
Cyndi King	Director of Treasury and Finance for ONE Gas	Supports the recovery of a return on TGS's portion of the prepaid pension asset.
Mark W. Smith	Vice-President and Treasurer for ONE Gas	Describes ONE Gas' captive insurance company, UIC.
Jeffrey J. Husen	Vice President, Chief Accounting Officer and Controller for ONE Gas	Addresses the Tax Cuts and Jobs Act of 2017 and the calculation of Excess ADIT.
Janet M. Simpson	Accountant and Vice-President at Dively Energy Services	Presents TGS's ADIT calculations.
Ronald E. White	Engineer and President of Foster Associates Consultants, LLC	Sponsors a study of the depreciation rates for TGS plant located in the proposed CGSA and for common facilities shared among all TGS service areas, including Corporate assets.
Bruce H. Fairchild	Principal with Financial Concepts and Applications, Inc.	Supports TGS's requested return on equity, cost of debt, capital structure, and overall return on invested capital.
Crystal D. Drumm	Rates Specialist for ONE Gas	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 options that allow for customer choice.

Christy M. Bell	Rates Analyst	Describes the proposed CGSA rate schedules and tariffs as well as rate schedules and tariffs currently in effect for the CTSA, GCSA, and the City of Beaumont.

III. RECOVERY OF INCENTIVE COMPENSATION COSTS

Q. PLEASE SUMMARIZE TGS'S REQUEST FOR RECOVERY OF INCENTIVE COMPENSATION COSTS IN THIS STATEMENT OF INTENT.

A. The Company's requested incentive compensation costs consist of Short-Term Incentive ("STI") and Long-Term Incentive ("LTI") compensation, which is paid to employees only if they and ONE Gas achieve certain operational, safety and financial goals. The Company is not requesting recovery of financially based incentive compensation costs for employees whose compensation is required to be disclosed under 17 C.F.R. Section 229.402(a) as identified in ONE Gas' Notice of Annual Meeting and Proxy Statement ("Named Executive Officers").

Q. ARE TGS'S REQUESTED INCENTIVE COMPENSATION COSTS REASONABLE AND NECESSARY?

A. Yes, they are. TGS is only seeking to recover its reasonable and necessary incentive compensation costs incurred during the test year ended June 30, 2019, updated for known and measurable changes through September 30, 2019. As mentioned previously, these costs 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 CGSA. Mr. Branz addresses the STI and LTI programs in his direct testimony.

Q. IS ONE GAS UNIQUE IN OFFERING EMPLOYEES INCENTIVE COMPENSATION?

A. No, ONE Gas is not unique in offering employees incentive compensation opportunities as a component of the overall compensation package as the market compensation studies indicate. Incentive compensation is necessary to provide a level of compensation that allows ONE Gas to attract and retain qualified employees who are necessary for the provision of safe and reliable service. In addition, ONE Gas' incentive compensation programs benefit customers by providing tangible ways to focus and motivate productive and efficient employee behavior.

Q. WHY IS IT APPROPRIATE FOR TGS TO RECOVER INCENTIVE COMPENSATION COSTS?

A. It is appropriate for TGS to recover its requested incentive compensation costs because they are a reasonable and necessary cost for the Company. As Mr. Branz's testimony states, total employee compensation, including STI and LTI pay, is reasonable and 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.

Q. ARE YOU FAMILIAR WITH ARGUMENTS TGS HAS FACED IN PRIOR RATE FILINGS CHALLENGING THE RECOVERY OF INCENTIVE COMPENSATION COSTS?

A. Yes, I am. In prior filings, TGS responded to arguments related to whether customers or shareholders benefited from a particular goal in the incentive compensation plans, including the position that TGS should recover incentive compensation costs only for achievement of operational or safety goals.

Q. DOES THE COMPANY AGREE WITH THE RATIONALE FOR THOSE CHALLENGES?

A. No. In my experience with regulatory filings, no other item in a utility's cost of service is subject to a customer-versus-shareholder benefit test for recovery of those costs. As I understand the standard for recovering costs, including for incentive compensation, the costs must only be reasonable and necessary in order to be recovered through rates. To meet this standard for recovery, TGS has provided evidence in prior cases demonstrating that the STI and LTI plans and goals are based on recent market studies and that incentive pay is designed to compensate employees in a reasonable way. Based on that evidence, which TGS has also presented in this filing, the incentive compensation costs requested by TGS should be considered reasonable and necessary and recovered through rates.

Q. ARE THERE ANY RECENT STATUTORY CHANGES RELATED TO INCENTIVE COMPENSATION COSTS?

A. Yes. Effective June 2019, Texas Utilities Code § 104.060 directly addresses a gas utility's request to recover employee compensation and benefits costs through rates. The new law states that base salaries, wages, incentive compensation and benefits shall be presumed reasonable and necessary if the expenses are consistent with market compensation studies issued not earlier than three years before the initiation of a rate case. Mr. Branz discusses in his testimony the recent market compensation studies ONE Gas uses to determine benefits, base pay, and incentive compensation levels. Under the statute, the presumption does not extend to incentive compensation for Named Executive Officers related to attaining financial goals. Ms. Borgstadt discusses the adjustment for incentive compensation costs, which includes removing incentive compensation related to financial metrics for Named Executive Officers, in her testimony.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF THE NEW STATUTE WITH RESPECT TO TGS'S INCENTIVE COMPENSATION COST RECOVERY IN THIS FILING.

A. Despite TGS providing market compensation studies in every recent rate case to support recovery of reasonable incentive compensation costs, that evidence did not mean TGS was able to recover all of its requested costs. Instead, in past cases, the Commission evaluated recovery of incentive compensation costs based on whether customers or shareholders were the purported beneficiaries of an incentive plan goal. The statute's focus on the use of market studies means that for the first time, all of the incentive compensation costs TGS seeks to recover in this case must be presumed to be reasonable and necessary costs that 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.

IV. MEAL AND HOTEL COSTS

Q. WHAT ARE THE COMPANY'S REQUESTS REGARDING MEAL AND HOTEL COSTS IN THIS STATEMENT OF INTENT?

A. TGS is requesting recovery of certain reasonable costs in excess of the $25-per meal and $150-per night thresholds. Specifically, TGS: (1) requests recovery of meal costs of $25 per person, per meal exclusive of tax and the tip amounts; and (2) after reviewing and analyzing the internal data on hotel expenses, requests recovery of certain hotel expenses over $150 per night when those costs are reasonable due to factors outside of ONE Gas' or the Company's control.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED TGS'S RECOVERY OF MEAL AND HOTEL COSTS?

A. Yes. For several years, the Commission and other parties in rate proceedings have reviewed the reasonableness of TGS's requested meal and hotel costs. In those cases, TGS removed meal costs in excess of $25 per person per meal and hotel costs greater than $150 per night, and using that practice, TGS's recovery of the remaining meal and hotel costs has not been controversial. During GUD No. 9988 in 2010, however, the Commission disallowed TGS's requested meal and hotel costs. At that time, the Commission had not established a consistent practice regarding these types of costs.

Q. WHAT DETERMINATION DID THE COMMISSION MAKE REGARDING TGS'S MEAL AND HOTEL COSTS IN GUD NO. 9988?

A. The Commission determined that TGS's supporting documentation of its travel and meal expenses was inadequate for regulatory review because the Company did not provide supporting documentation with sufficient detail to allow parties or the Commission to determine whether the meal and hotel costs were reasonable, necessary, and related to the provision of gas service.

Q. SINCE THE COMMISSION ISSUED THE FINAL ORDER IN GUD. NO. 9988 IN 2010, HAS ONE GAS OR TGS MADE ANY CHANGES TO MEAL AND HOTEL EXPENSE PROCESS AND PROCEDURES?

A. Yes. Since the Final Order was issued in GUD No. 9988, ONE Gas and the Company have made significant improvements related to requirements for employee meal and hotel expenses, including required documentation. ONE Gas reviews its Business Travel and Expenditure Policy, attached to my testimony as

Confidential Exhibit GDS-2, to update it when necessary, and the table below provides a summary of revisions that were made to the Business Travel and Expenditure Policy between 2010 and 2018.

Business Travel and Expenditure Policy

2010	2018
Receipts required for expenses greater than $25.00	Meals - itemized receipt required
Online credit card statement includes a description of each charge.	Meals - must include the business purpose of the meal.
Meals charged to a hotel room must be show separately and be identified as meals.	Catering - Groups exceeding 5 attendees must include headcount
Original receipts for hotels must be attached to an expense report regardless of the amount.	Meals with alcohol must be identified as “Meal with Alcohol” with the alcohol itemized.
Monthly, 10 employees were selected for an audit of their submitted online credit card forms. These were reviewed to ensure the employee and approving manager were in compliance with the policy regarding receipts, authorized charges, and appropriate descriptions.	Entertainment that included alcohol must be identified as “Entertainment with Alcohol” with the alcohol charges itemized.
	ONE Gas has negotiated rates with certain hotels, which should be used when possible.
	Hotel charges must be supported with the Itemized Receipt. Itemized Receipts are also required for meals charged to the room.
	The supervisor approving the expense report is responsible for ensuring the reports are submitted timely, includes required documentation, and charges are reasonable and consistent with Company policy.
	Supervisors are responsible for ensuring their employees are educated about and follow this policy and for resolving any policy violations. Supervisors may be more restrictive than this policy, but cannot be less restrictive.
	Expense reports are randomly selected for audit by Concur to ensure the charges and supporting documentation follow ONE Gas’ policy.

Q. HOW DOES THE ONE GAS BUSINESS TRAVEL AND EXPENDITURE POLICY ADDRESS MEAL AND HOTEL EXPENSES INCURRED BY EMPLOYEES?

A. At times, ONE Gas and TGS business require that our employees work at locations other than their offices or primary work locations. This can occur when an employee must attend training or meet with customers and other stakeholders. For example, employees incur expenses when they work in the field to ensure the reliability of the Company's facilities and equipment, restore service after a natural disaster, manage employees across ONE Gas' three-state service territory, or travel to attend conferences or training to maintain their knowledge and skills. For instance, the Company has determined based on a review of internal data that approximately 84% of hotel stays that occurred during the test year were in ONE Gas' three states of operation (Kansas, Oklahoma, Texas). In addition, the Company's manual review of hotel costs showed that approximately 70% of hotel stays were less than $150 per night, exclusive of taxes, demonstrating the Company is managing hotel costs well.

The Business Travel and Expenditure Policy requires that meal and lodging expenses be reasonable, while providing the employee with a certain level of safety, service, and comfort. ONE Gas has negotiated lodging rates, and employees must use these hotels when possible. Hotel and meal costs must also be supported with an itemized receipt. After an employee incurs meal or hotel costs, the employee's direct supervisor is responsible for verifying and confirming that all charges are in compliance with ONE Gas' policies, are business-related, reasonable under the circumstances and properly supported by receipts or other documentation.

Q. DOES THE BUSINESS TRAVEL AND EXPENDITURE POLICY ADDRESS TIPS?

A. Yes. Section 8.1 of the policy explains that business meals should include a reasonable tip that ranges from 15-20% or a minimum of $2.00. If employees exceed the tip amounts in the policy, the additional amount may be considered a personal expense, and the employee would be responsible for reimbursing ONE Gas for that amount.

Q. ARE THERE ADDITIONAL TOOLS ONE GAS AND THE COMPANY USE TO TRACK EXPENSES?

A. Yes. In 2012, an expense tracking software, Concur, was purchased to facilitate managing employee expenses. Prior to the implementation of Concur, the efforts to identify meal, alcohol, and lodging activity that exceeded previously used threshold amounts were extremely time intensive and manually driven. For example, one of the challenges at the time of GUD No. 9988 was that the accounting system could not track the number of people at a meal. In addition, the accounting system could not reflect the number of nights stayed in a hotel or whether the charges were for more than one person's room. There are instances where more than one employee's room may be included on one bill and for more than one night. Lastly, the accounting system could not identify that an expense was related to alcohol.

Q. HOW DOES CONCUR ASSIST WITH MANAGING BUSINESS AND TRAVEL EXPENDITURES AT ONE GAS AND THE COMPANY?

A. Concur requires detailed information from the employee to finish an expense report, such as the name or number of attendees for meals, dates the employee(s) stayed in a hotel, and transactions can be flagged as "Meal or Meal/Entertainment with Alcohol." Concur lets the employee know of potential inconsistencies with the Employee Expense Policy and also prompts the employee to provide any missing information. In addition, an electronic copy of all receipts must be included with the expense report for manager review and approval. If information provided in Concur does not comply with ONE Gas guidelines, the transaction is flagged for further review during the approval or audit process. Concur requires an employee to provide the transaction date, expense type, expense category, business purpose, transaction amount, merchant name and locations, meal attendee names or number of attendees at a catering activity, meals with alcohol (if applicable), and hotel stay dates providing the number of nights.

Q. DOES CONCUR INCLUDE AUDITING FUNCTIONALITIES THAT ALLOW FOR FURTHER REVIEW OF THE COSTS?

A. Yes. The audit process is identified as Concur Detect and performs a 100% analysis of each expense report. Concur Detect checks each report for multiple scenarios and applies a risk rating (low, medium, high) to each report. Each report assigned a high risk will be sent to the Treasury department to review and determine whether the report should be returned to the employee for correction or continue to be processed for approval. Items reviewed during the Concur Detect process include verification that receipts are attached to each expense report, verification that hotel costs are itemized as required by ONE Gas policy, and flagging any potential unauthorized expenses.

Q. WHAT STEPS DOES THE COMPANY TAKE REGARDING POTENTIAL NON-COMPLIANCE ISSUES WITH EMPLOYEE EXPENSES?

A. ONE Gas' Treasury department investigates to determine if the item is in violation of policy. If the item is a violation, then the report is returned to the employee and supervisor with an explanation and additional training so they can make the correction and resubmit the report to comply with the policy. If expenses have been incurred that are not consistent with the policy, the employee will reimburse ONE Gas.

Q. HAS THE COMMISSION ESTABLISHED A CONSISTENT PRACTICE RELATED TO RECOVERY OF MEAL AND HOTEL COSTS SINCE GUD NO. 9988?

A. Yes. The Commission has determined that it is reasonable for utility rates to include meal costs up to $25 per meal per person, excluding taxes, and lodging costs up to $150 per night, excluding taxes.[5] In addition, the Commission has also determined that a utility has the opportunity to show that costs in excess of those amounts are also reasonable.[6]

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[5] *Statement of Intent Filed to Change the Rate CGS and Rate PT of Atmos Pipeline - Texas*, GUD No. 10000, Final Order at FoF 33 (April 18, 2011).

[6] *Id*. at 14. In addition to applying the meal and hotel thresholds in GUD No. 10000, the Commission ordered Atmos Pipeline-Texas to establish that "any expenses in excess of $25 for meals and $150 for lodging are just and reasonable, exclusive of taxes."

Q. WHY IS THE COMPANY REQUESTING RECOVERY OF TIPS AND TAXES IN ADDITION TO RECOVERY OF MEAL COSTS UNDER $25 PER PERSON PER MEAL?

A. The Company's position in this case is consistent with the language in the Final Order in GUD No. 10000, in which the Commission determined that it is reasonable that the $25 per meal per person exclude taxes. Based on the language in the Final Order from GUD No. 10000, it appears that the Commission was trying to recognize and exclude the additional reasonable costs associated with a meal and only address the actual cost of the meal. In addition, tips employees include with meal costs must also comply with the Business Travel and Expenditure Policy, which I explained above. For these reasons, the Company requests a similar exclusion for tip amounts to allow reasonable tips to also be recovered through rates.

Q. WHY HAS THE COMPANY INCLUDED CERTAIN HOTEL EXPENSES OVER $150 PER NIGHT?

A. According to the Final Order issued in GUD No. 10000, the utility must establish that any expense in excess of $150 per night for hotels is just and reasonable, exclusive of taxes. While the Company Business Travel Expenditures policy does not place a specific dollar limit on hotel expenses, costs for lodging must be reasonable, while providing the employee a reasonable level of convenience, safety, service and comfort. Here, the $150 per person per night does not allow for consideration of reasonable judgment in instances in which appropriate lodging options are not available at or below that specific rate. For example, it may be more efficient for an employee to stay downtown in a higher priced hotel and be able to walk to a business meeting. Additionally, as Ms. Allison Edwards explains in her testimony, the costs of hotels fluctuate between the geographic locations to which the employees are required to travel.

Q. ARE THE MEAL AND HOTEL COSTS INCLUDED IN THE COMPANY'S STATEMENT OF INTENT FILING REASONABLE AND NECESSARY?

A. Yes. The Company has reviewed this issue in past cases including GUD No. 9988 and followed the recommendations and findings in those cases in order to improve its documentation of the reasonableness and necessity of these costs. The Company supports the Commission and parties' reviewing all costs, including meal and hotel costs, to confirm the Company will recover only reasonable and necessary costs. The Company has shown that for hotels, there are times when issues related to safety, geography, or seasonality, support a finding of reasonableness for hotel costs that are more than $150 per night. In addition, compliance with ONE Gas' Business Travel Expenditure Policy also supports the reasonableness and necessity of the meal and hotel costs that TGS is requesting to recover in this case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019

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Texas Gas Service Company, a Division of ONE Gas, Inc.
CGSA ISOS RTCS TYE June 30, 2019
Updated for Known and Measurable Changes Through September 30, 2019

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Exhibit GDS-2 is Confidential
and will be provided pursuant to the terms of the Protective Agreement.

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF G. DAVID SCALF

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

1. "My name is David Scalf. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Vice President of Rates and Regulatory Affairs 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.

G. David Scalf

SUBSCRIBED AND SWORN TO BEFORE ME by the said G. David Scalf on this 9th day of December, 2019.

JOANNE C. DAVIS NOTARY # 05009895 EXP. 10/25/21 PUBLIC STATE OF OKLAHOMA

Joanne C Davis
Notary Public in and for the State of Oklahoma

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

SHANTEL NORMAN

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

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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 1301 South MoPac Expressway, Suite 400, Austin, Texas 78746.

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 in the Company's six service areas in Texas. These responsibilities include:

- Construction and maintenance on TGS's distribution and transmission 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 and 10766.

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 Central Texas Service Area ("CTSA") and the Gulf Coast Service Area ("GCSA") and related environs areas that are the subject of this rate filing. I also support the Company's request to consolidate the CTSA and GCSA as well as the City of Beaumont into a new, combined service area that will be known as the Central-Gulf Service Area ("CGSA") if consolidation is approved. In addition, my testimony, along with the testimony of other TGS witnesses, supports the reasonableness and necessity of the Company's requested O&M expenses in the proposed CGSA and a determination that the capital investment that has been made in the proposed CGSA through June 30, 2019, adjusted for known and measurable changes through September 30, 2019, is used and useful and was prudently incurred. In addition, certain plant balances will be updated after December 31, 2019, which will support a prudence determination for capital investment through December 31, 2019.[1] The capital investment included in this case includes Direct,

[1] As Company witnesses Gracie Guerra and Mindy Edwards explain, TGS included September 30, 2019 CWIP balances as an adjustment to CCNC. TGS will true-up net plant after December 31, 2019 to exclude any plant that is not used and useful at that time and will provide updated plant in service amounts, CCNC and accumulated reserves balances by February 14, 2020.

TGS Division and Corporate investments. My testimony demonstrates that this capital investment and the related expenses are a necessary part of maintaining a safe and reliable natural gas distribution system.

I also address ONE Gas' recent acquisition of ONEOK Transmission Company ("OTC") from ONEOK, Inc. ("ONEOK"), including an explanation of TGS's activities as the operator of the pipeline and the Company's desire to integrate the pipeline into TGS's system. ONE Gas Pipeline Company ("OPC") is an affiliate of TGS that was created at the time of the acquisition to hold the former OTC assets. My testimony on this subject supports testimony filed by Company witness Stacey L. McTaggart, who addresses and supports TGS's request for a finding from the Commission that the acquisition of OTC is consistent with the public interest. Finally, I describe the reasonableness and necessity of the Company's Pipeline Integrity Testing expense.

II. TGS SYSTEM AND OPERATIONS

Q. PLEASE DESCRIBE THE TGS SYSTEM AND ITS OPERATIONS IN TEXAS.

A. TGS is a division of ONE Gas, which operates as an independent natural gas distribution company focusing on delivering natural gas safely and reliably to customers in Oklahoma, Kansas and Texas and is headquartered in Tulsa, Oklahoma. TGS provides safe, clean and reliable natural gas service to approximately 663,000 customers in 100 communities within its six service areas in Texas. A map of the areas TGS currently serves is attached to my testimony as Exhibit SN-1. As of June 30, 2019, ONE Gas is also now the owner of a pipeline formerly owned by ONEOK, located in TGS's CTSA. I address this in more detail below.

Q. PLEASE ELABORATE ON 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; (2) total recordable incident rate; and (3) days away, restricted and transferred. Exhibit SN-2 shows ONE Gas' progress over the last several years with respect to the first three metrics compared to general industry achievement based on data gathered by the American Gas Association. The data in Exhibit SN-2 confirms that ONE Gas has improved significantly from being in the 4th quartile in 2009 to the 1st quartile in recent years. In early 2019, ONE Gas added an additional metric, which measures how often Company personnel arrive onsite for an emergency call out in less than thirty minutes. For the newest metric, Exhibit SN-2 shows only one partial year of data, because that is when ONE Gas began tracking the information. The data in Exhibit SN-2 demonstrates an improvement in the percent of onsite arrivals less than thirty minutes since ONE Gas implemented the metric. Exhibit SN-2 also confirms that ONE Gas is exceeding its 2019 target for the onsite time metric of 63% on a year-to-date basis.

Q. PLEASE DESCRIBE THE SERVICE AREAS THAT ARE THE SUBJECT OF THIS STATEMENT OF INTENT.

A. TGS proposes to consolidate two of its existing service areas, the CTSA and the GCSA, to form a new, combined service area called the Central-Gulf Service Area. The Company also provides service to a few customers within the city of Beaumont and is seeking to include Beaumont in the proposed CGSA as well. If consolidation for the CGSA is not approved, TGS requests the City of Beaumont to be consolidated into the GCSA. TGS provides natural gas distribution service to more than 265,420 customers in the CTSA, which includes the incorporated and environs areas of Austin, Bee Cave, Cedar Park, Cuero, Dripping Springs, Gonzales, Kyle, Lakeway, Lockhart, Luling, Nixon, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, and the environs of Buda. In addition, TGS provides service to 44,436 customers in the GCSA, which includes the incorporated and environs areas of Bayou Vista, Galveston, Groves, Jamaica Beach, Nederland, Port Arthur, and Port Neches, and the environs areas of Beaumont. If the proposed service area consolidation is approved, all of the cities and environs areas would be served as part of the CGSA. TGS and its predecessor utilities have served these areas for approximately 85 years through a system that includes approximately 2,947 miles of distribution mains and 1,843 miles of service lines in the CTSA and 807 miles of distribution mains and 572 miles of service lines in the GCSA. These system assets combined represent more than $534,696,683 in net investment. As of the end of the test year, the Company directly employed 415 Division and Direct CTSA and GCSA people with a combined annual payroll of $28,083,252 and remitted nearly $3.9 million in annual property taxes to local taxing authorities in the CTSA and GCSA.

Q. PREVIOUSLY YOU MENTIONED ONE GAS' ACQUISITION OF A PIPELINE FROM ONEOK. PLEASE DESCRIBE THE PIPELINE AND ITS OPERATIONS.

A. ONE Gas acquired OTC and its assets from ONEOK on June 30, 2019. As part of the transaction, ONE Gas formed an affiliate of TGS called ONE Gas Pipeline Company to own the assets. The assets are located in the existing CTSA. Prior to ONE Gas' acquisition of the pipeline, TGS had operated the line for ONEOK since 2003. Since the acquisition, TGS continues to operate the pipeline under the existing Operating Agreement. There was no interruption or disruption in service to customers after the acquisition. Ms. McTaggart addresses affiliate issues related to OPC in her testimony.

Q. PLEASE EXPLAIN THE COMPANY'S FUNCTIONAL OPERATING MODEL.

A. As TGS noted in prior CTSA and GCSA rate cases, ONE Gas' functional operating model has been in place since 2013 and allows ONE Gas to operate its LDCs 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, ONE Gas can better align common processes across the enterprise, regardless of the state where that function is completed.

The centralized approach to decision-making processes and management of the Company's gas service means that the employees within the service area boundaries do not represent the full scope of the activities, personnel and workload associated with the Company's actual operations in the CTSA or GCSA. 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. Examples of functions that are centralized at ONE Gas include Asset Management and Resource Management. Examples of functions that are centralized at a statewide level include:

- Leak survey;
- Pressure control and measurement;
- Cathodic protection; and
- Line locating.

Examples of departments that are centralized at the statewide level include the following departments:

- 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 the Company and ONE Gas related to operation of the Company's system.

Q. ARE CAPITAL INVESTMENT DECISIONS BASED ON THE NEEDS OF THE ENTIRE TGS SYSTEM RATHER THAN THE NEEDS OF ANY INDIVIDUAL SERVICE AREA?

A. Yes, they are. Project planning and management is coordinated at a Company-wide level. An increase in regulatory focus by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") on the timely monitoring and repair or replacement of utilities' assets has led ONE Gas to establish a work group that focuses on and coordinates the monitoring and replacement activity throughout all service areas. Personnel from the Company's Engineering Department and Operations Department identify potential projects. The Asset Management Department then optimizes potential projects utilizing a risk-based approach and prioritizes the proposed projects based on the relative risk. Additionally, Asset Management develops optimized annual and long-term work plans by proposing projects throughout the Company that maximize risk reduction under given financial, resource and regulatory constraints.

Q. WILL THE COMPANY'S REQUEST FOR CONSOLIDATION AFFECT OPERATIONS IN THE PROPOSED SERVICE AREA?

A. No. The geographic location of a TGS service area does not dictate how the Company operates in a given region, and many of the same people, myself included, are regularly involved in the coordinated operation, maintenance and management of the Company's system throughout the state.

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, a centralized Customer Information Center ensures that customers within the proposed CGSA 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 CGSA 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 more effectively monitor the status of its assets within the CGSA.

Q. IN YOUR OPINION, IS THE CREATION OF THE CGSA, AS DESCRIBED ABOVE, REASONABLE FROM AN OPERATIONAL PERSPECTIVE?

A. Yes, it is reasonable given the coordinated way in which TGS operates and maintains its system in the existing service areas, as well as managing those activities at the TGS and ONE Gas levels. It is important to note that TGS will not have to adopt new operational changes if the Commission approves the consolidation request because any operational changes necessary to operate in a coordinated manner have already taken place. The proposed consolidation simply reflects the operating changes that have already occurred. As I discussed above, the existing areas have similar operations, already share personnel for certain services, and rely on centralized management of certain functions and operations.

III. OPERATIONS AND MAINTENANCE EXPENSES

Q. WHAT ARE O&M EXPENSES?

A. These are expenses that relate to the normal operating, maintenance and administrative activities of a business.

Q. PLEASE DESCRIBE THE O&M EXPENSES THAT ARE NECESSARY TO PROVIDE SAFE AND RELIABLE SERVICE.

A. One of the primary drivers of O&M expense is maintenance activities that are performed daily to provide safe and reliable gas service and effective and efficient customer service. In addition, TGS must invest in its employees and has experienced reasonable and necessary increases in personnel-driven expenses, such as wages and salaries and employee benefits, which Company witnesses Stacey R. Borgstadt and Jeff D. Branz address in more detail in their testimonies. Company employees are in the field performing tasks necessary for safety and regulatory compliance, such as:

- Cathodic protection;
- Distribution integrity;
- Leak survey;
- Leak monitoring;
- Leak repair; and
- Line locating.

Similarly, technicians perform tasks that include:

- Meter maintenance;
- Pressure regulation;
- Odorant testing;

- Service initiation; and
- Right-of-way maintenance.

These operational functions are supported by back-office functions necessary to operate the natural gas distribution system in a safe and reliable manner and provide outstanding customer service.

Q. PLEASE ELABORATE ON THE COMPANY'S REGULATORY COMPLIANCE OBLIGATIONS.

A. The Company is subject to many rules and regulations imposed by the Federal and state governments. For instance, pursuant to Commission Rule § 8.206(g), TGS has adopted a prescriptive program for leak surveys that requires the Company to conduct leak surveys no less frequently than:

1) Annually for all systems within a business district;
2) Every five years for non-business district polyethylene systems or segments within a system;
3) Every three years for all other non-business district, cathodically protected steel systems or segments within a system; and
4) Every two years for all other non-business district systems or segments within a system.

Likewise, pursuant to PHMSA requirements applicable to natural gas distribution companies[2] the Company has developed and implemented a distribution integrity management program ("DIMP"). These PHMSA regulations require the operator to establish a risk-based approach to pipeline maintenance and safety rather than

[2] *See generally* 49 C.F.R. 192.1001-.10015 (2017) (distribution integrity management standards).

adhere to a prescriptive set of uniform regulations applicable to all operators. As a companion to DIMP, Commission Rule § 8.209 requires all natural gas distribution companies to develop and implement a risk-based program for the removal or replacement of distribution facilities, including steel service lines. The risk-based program works in conjunction with the DIMP, using scheduled replacements to manage identified risks associated with the integrity of distribution facilities.

Q. HAS ONE GAS TAKEN THE INITIATIVE TO IMPLEMENT MORE STRINGENT PROCESSES AND PROCEDURES TO ENSURE THE SAFETY OF ITS DISTRIBUTION SYSTEM?

A. Yes. ONE Gas has 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. In 2017, the Company began utilizing LocusSurvey to schedule, plan and complete leak survey activities. LocusSurvey is a mobile application that uses GPS-enabled smartphones to track leak survey routes and capture survey results. The location of the leak survey route is overlaid onto a GIS map of the TGS assets to track pipe segments that have been surveyed to provide near real-time reporting and monitoring.

Q. WHAT EFFORTS DOES TGS TAKE TO CONTROL O&M COSTS ON AN ON-GOING BASIS?

A. 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 mix of contractors and in-house labor 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 service area boundaries 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.

Q. DOES THE PROCUREMENT PROCESS ALSO HELP TGS CONTROL O&M COSTS?

A. Yes, it does. 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. WHAT IS THE AMOUNT OF O&M EXPENSE BEING REQUESTED IN THIS FILING?

A. The O&M amount requested is approximately $80 million. Of this amount, approximately $48,474,104 is attributable to O&M activities undertaken directly by the CTSA and GCSA and approximately $31,972,112 is attributable to allocated costs, which include TGS Division and ONE Gas Corporate costs necessary to provide service in these service areas. Company witness Anthony Brown sponsors the allocated costs. TGS is also requesting an adjustment to O&M expense to reflect costs related to operating and maintaining the OPC pipeline, which is being integrated into TGS's existing system. Company witness Marie Michels addresses this adjustment in her testimony.

Q. HOW WAS THE AMOUNT OF THE O&M ADJUSTMENT RELATED TO OPC DETERMINED?

A. Prior to ONE Gas' acquisition of OTC, TGS operated and maintained the pipeline for ONEOK. After the acquisition, TGS continued those activities for OPC. TGS would bill or invoice OPC monthly for the O&M expenses TGS incurred, and OPC would reimburse TGS for that service. The post-test year adjustment to reflect necessary O&M costs TGS will incur when the pipeline is part of TGS's system is based on TGS's historical experience with actual O&M costs for the OPC line.

Q. PLEASE DESCRIBE WHAT O&M ACTIVITIES TGS PERFORMS ON THE OPC ASSETS AND HOW IS THAT COST DETERMINED?

A. TGS performs the same O&M activities for the OPC assets as it does for other system assets. These include leak repair, leak survey, right of way maintenance, line locating, standby during third party digging, odorization, operation and maintenance of regulators, and installation and monitoring of cathodic protection. Company employees or contractors perform these activities at the same cost TGS incurs for its own O&M activities.

Q. IS THE LEVEL OF O&M EXPENSE REQUESTED IN THIS FILING REASONABLE AND NECESSARY?

A. Yes, it is. The level of O&M expense requested is reasonable and necessary to continue the safe and reliable operation of the system and to provide effective and efficient customer service. Moreover, the services provided by TGS Division and

Corporate employees are integral to the provision of safe and reliable service to customers and, as Mr. Brown explains, are also reasonable.

IV. CAPITAL INVESTMENT

Q. WHAT IS CAPITAL INVESTMENT?

A. Capital investment is money used for the acquisition and installation of equipment or facilities that are expected to have an extended period of use prior to being replaced or retired. Capital investment in TGS's infrastructure and other assets is necessary to maintain and expand the utility system in order to provide safe and reliable service to customers. Safety, reliability and growth are the primary drivers behind most of the capital investment made in the proposed CGSA.

Q. HAS THE COMPANY INCLUDED CAPITAL INVESTMENT MADE IN THE PROPOSED CGSA IN THIS STATEMENT OF INTENT FILING?

A. Yes, this filing includes capital investment made in the proposed CGSA since the last rate cases in the CTSA and GCSA through the test year ending June 30, 2019 and a known and measurable adjustment for capital invested through September 30, 2019.[3] In addition, as I noted previously, certain plant balances will be updated through December 31, 2019, and TGS will provide that information. TGS is requesting a prudence determination for capital investment made: (1) from January 1, 2016 through December 31, 2018 for the GCSA environs and for the incorporated and unincorporated areas of the CTSA; and (2) from January 1 through December 31, 2019 for the environs and incorporated areas of the GCSA and CTSA. Exhibits SN-3 and SN-4 contain investment reports for capital

[3] TGS serves Beaumont customers using GCSA plant.

investment in CTSA and GCSA, including Corporate and TGS Division investment, for January 1, 2016 through September 30, 2019.[4] TGS is not requesting a prudence determination for investment in the incorporated areas of the GCSA made from January 1, 2016 through December 31, 2018 because the cities within the GCSA already made the necessary prudence determination in the Company's annual Cost of Service Adjustment filings.

Q. DO THE CAPITAL INVESTMENT AMOUNTS FOR WHICH TGS IS REQUESTING A PRUDENCE DETERMINATION INCLUDE INVESTMENTS REFLECTED IN TGS'S INTERIM RATE ADJUSTMENT FILINGS?

A. Yes. The capital investments amounts include the investments reflected in TGS's interim rate adjustment filings (collectively referred to as the "GRIP filings") as follows:

CTSA Incorporated:

GRIP Period	Date of City Ordinances
2016	May - June 2017
2017	April - May 2018
2018	May - June 2019

CTSA Environs:

GUD No.	GRIP Period	Date of Final IRA Order
10610	2016	June 6, 2017
10714	2017	June 5, 2018
10824	2018	June 4, 2019

GCSA Environs:

GUD No.	GRIP Period	Date of Final IRA Order
10666	2016	March 20, 2018
10781	2017	January 23, 2019
10857	2018	September 11, 2019

[4] By February 14, 2020, TGS will provide an investment report for capital investment for October 1, 2019 through December 31, 2019.

In addition, the Company requests a determination that its GRIP filings are just and reasonable in accordance with Texas Utilities Code § 104.301.

Q. PLEASE DESCRIBE THE CAPITAL INVESTMENT THAT HAS BEEN AND CONTINUES TO BE MADE IN THE PROPOSED CGSA.

A. Generally, these capital investments are made to: (1) comply with regulatory requirements; (2) replace pipeline facilities that have reached the end of their useful service lives; (3) add pipeline for serving new customers; and (4) relocate pipeline facilities as required by city, county and state roadway projects.

Some examples include:

- Replacement of approximately 2,100 feet of 12-inch bare steel main and nearly 1,000 feet of 12-inch coated steel main and services with new 12-inch coated steel main along Dean Keeton Boulevard in the City of Austin. The replacement of aging pipe in a heavily populated area improved the safety and reliability of the system.
- Relocation of approximately 1,020 feet of 4-inch polyethylene main and twelve services lines to accommodate a City of Austin storm drain project on Wooldridge Drive.
- Replacement and relocation of main along 25th Street in the City of Galveston in connection with the City's repaving and drainage system improvements.

Q. IN TERMS OF CAPITAL PROJECTS, HOW MUCH HAS THE COMPANY INVESTED IN THE PROPOSED CGSA SINCE THE LAST RATE CASES?

A. TGS is committed to making the investments necessary to replace aging infrastructure and respond to the needs of its customers. Since 2016, the Company has, on a combined basis, increased its net plant in the proposed CGSA by approximately $39 million per year or 8.65% per year, which totals $157 million as shown on Exhibit SN-5. These capital costs are necessary for the Company's operations and are reasonable and prudent.

Q. HAVE ANY ADJUSTMENTS BEEN MADE TO CAPITAL INVESTMENTS IN THIS FILING?

A. Yes, in addition to an adjustment for Plant in Service through September 30, 2019, the Company has proposed other adjustments to capital investment. These adjustments are addressed by Ms. Guerra and Ms. Mindy Edwards.[5]

Q. WILL CAPITAL INVESTMENT FOR THE OPC ASSETS BE INCLUDED IN TGS'S REQUESTED CAPITAL INVESTMENT AND PRUDENCE REVIEW IN THIS CASE?

A. Yes. Ms. McTaggart and Ms. Guerra address the rate base amount for OPC in their direct testimony.

Q. ARE THE OPC ASSETS USED AND USEFUL FOR THE PROVISION OF SERVICE?

A. Yes. As I noted previously, TGS has operated and maintained the assets for several years and continues to do so currently under ONE Gas' ownership. Specifically, OPC provides service to eleven customers on the assets.

[5] Ms. Guerra addresses direct plant and any adjustments to direct plant, while Ms. Edwards addresses TGS Division and ONE Gas corporate plant and any adjustments to this plant.

Q. COULD YOU PLEASE PROVIDE SOME ADDITIONAL INFORMATION ABOUT TECHNOLOGY INVESTMENTS THAT SERVE TO REDUCE RISK, INCREASE EFFICIENCY AND ENHANCE CUSTOMER SERVICE?

A. One area where TGS has invested in technology is asset investment and planning. TGS has implemented technology to enhance the Company's planning process and expand the planning horizon. These investments increase the safety and reliability of the TGS system by helping to ensure pipeline replacements are prioritized appropriately and capital investments are made in a cost-effective and efficient manner. ONE Gas also utilizes a work management system to increase operational capabilities, efficiencies and record-keeping. This system provides enhanced dispatching of operations, enhanced data capture through integrated record-keeping, the elimination of paper, and improved mapping. Crews now have information and records about TGS's facilities available on their mobile devices and they are capturing their work electronically in the field.

Q. PLEASE DESCRIBE THE PROCESS BY WHICH THE COMPANY IDENTIFIES CAPITAL PROJECTS.

A. Projects are identified by the Company's Asset Management, Resource Management, Engineering, and Operations personnel, who in turn work with federal, state, and local governmental authorities, as well as private developers, to determine where new system investments need to be made. 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.

Q. ARE ALL CAPITAL INVESTMENTS ESTABLISHED AT THE BEGINNING OF EACH FISCAL YEAR?

A. No, they are not. Based on experience, the Company recognizes that 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 budget 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 late 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. DOES THE COMPANY HAVE PROCESSES IN PLACE TO CONTROL CAPITAL COSTS?

A. Yes, it does. All the Company's processes for identifying, prioritizing, evaluating, reviewing, and managing capital projects are designed to ensure that every capital investment in the system is necessary for providing safe and reliable service and reasonable in cost. 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 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. DOES THE PROCUREMENT PROCESS ALSO HELP CONTROL CAPITAL COSTS?

A. Yes, by utilizing a centralized purchasing department, the Company can take advantage of volume discounts through approved vendors. Direct purchases of materials are kept to a minimum.

Q. IS ALL THE CAPITAL INVESTMENT INCLUDED IN THE COMPANY'S FILING AND BOOKED TO PLANT USED AND USEFUL IN PROVIDING UTILITY SERVICE?

A. Yes, it is. All investments included in this filing are currently used and useful in providing utility service as of the end of the test year and adjustments through September 30, 2019.[6]

Q. ARE ALL THE CAPITAL INVESTMENTS INCLUDED IN THE COMPANY'S FILING REASONABLE AND NECESSARY?

A. Yes, they are reasonable and necessary. Each capital investment must be approved through a thorough decision-making process. Each investment made in the proposed CGSA was prudent, reasonable in amount, and necessary for TGS to maintain a safe and reliable system and to provide an appropriate level and quality

[6] Given the nature of the Company's adjustment regarding CWIP as described in the testimonies of Ms. Guerra and Ms. Edwards, the Company anticipates that the final number will be known following the end of calendar year 2019.

of gas utility service to our customers. This is also true for TGS Division and Corporate investment that is allocated to the proposed CGSA and contributes to the Company's ability to provide service in the proposed CGSA.

Q. DO ANY ADDITIONAL FACTORS AFFECT CAPITAL INVESTMENTS?

A. Yes. Pipeline safety and system integrity requirements imposed by the federal government through statute and regulations, which the Company supports, require significant capital investment and lead to increased operating costs. To respond to these challenges, 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 part of the Company's on-going capital budget, and during the test year ending June 2019, TGS retired or replaced over 9.5 miles of distribution mains in the proposed CGSA. The Company has implemented new technology to reduce risk, increase operational capabilities and efficiencies and improve customer service.

V. PIPELINE INTEGRITY TESTING PROGRAM

Q. WHAT IS THE PIPELINE INTEGRITY TESTING PROGRAM AND WHAT AGENCIES ARE RESPONSIBLE FOR ITS ADMINISTRATION?

A. Pipeline integrity testing is a combined federal and state regulatory initiative designed to ensure the safe transportation of natural gas by pipeline by requiring pipeline operators to regularly test the structural integrity of their gas pipelines. It is part of a broader national regulatory program implemented by the federal Office of Pipeline Safety ("OPS") within PHMSA to ensure the safe transportation of natural gas, petroleum, and other hazardous materials. These regulations are found in 49 C.F.R. Part 192, Subpart O. The OPS works in partnership with the

Commission and its counterparts in other states to achieve the program's public safety objectives. In Texas, the Commission has been delegated responsibility for administering and enforcing pipeline integrity requirements for intrastate pipelines and, to that end, has adopted state regulations that supplement the applicable regulations and requirements of PHMSA. The Company's pipeline integrity testing program is specifically implemented to comply with these state and federal regulations.

Q. WHEN DID TGS FIRST IMPLEMENT ITS PIPELINE INTEGRITY TESTING PROGRAM?

A. The initial testing began in 2003. Under the program, TGS tested all transmission facilities subject to the regulations as part of a Baseline Assessment over a ten-year period. Since that Baseline Assessment was conducted, TGS is required to reassess its facilities at least once every seven years, with certain higher risk facilities subjected to more frequent testing. The Company has 11.7 miles of gas transmission main in the proposed CGSA subject to this integrity testing.

Q. DOES THE COMPANY TEST ROUGHLY THE SAME LENGTH OF PIPELINES EACH YEAR IN ORDER TO MEET THE PROGRAM'S REQUIREMENTS?

A. No, it does not. Pursuant to state and federal regulations, the Company must assess risks to its entire pipeline across the state in order to determine the priority by which pipelines should be tested each year.[7] Once the risk assessment and testing schedule has been established statewide, TGS coordinates and schedules testing in

[7] Texas Administrative Code, Title 16, Rule §8.101 and Rule §8.209 and 49 C.F.R. §192.937 and 49 C.F.R. §192.1001.

an efficient and cost-effective manner. Accordingly, the miles of pipe tested and the associated level of expense in a given year may vary. Ms. McTaggart and Company witness Christy M. Bell discuss the Company's proposal to account for and recover these necessary expenses in the proposed CGSA.

Q. ARE PIPELINE INTEGRITY TESTING COSTS REASONABLE AND NECESSARY?

A. Yes, they are reasonable and necessary. The Company is required to incur these costs pursuant to federal and state regulations that require the Company to regularly test its pipelines. The Company only seeks to recover the actual costs it incurs in meeting the requirements of the pipeline integrity testing program. Moreover, given the nature and focus of this important safety initiative, it is important that the Company recover those costs on a timely basis. In addition, the Commission and many cities in which TGS operates have previously approved the Company's request to recover pipeline integrity testing costs through an annual rider, which Ms. McTaggart addresses in her testimony.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Texas Gas Service Company, a Division of ONE Gas, Inc.
CGSA ISOS RTCS TYE June 30, 2019
Updated for Known and Measurable Changes Through September 30, 2019

TGS SERVICE AREAS

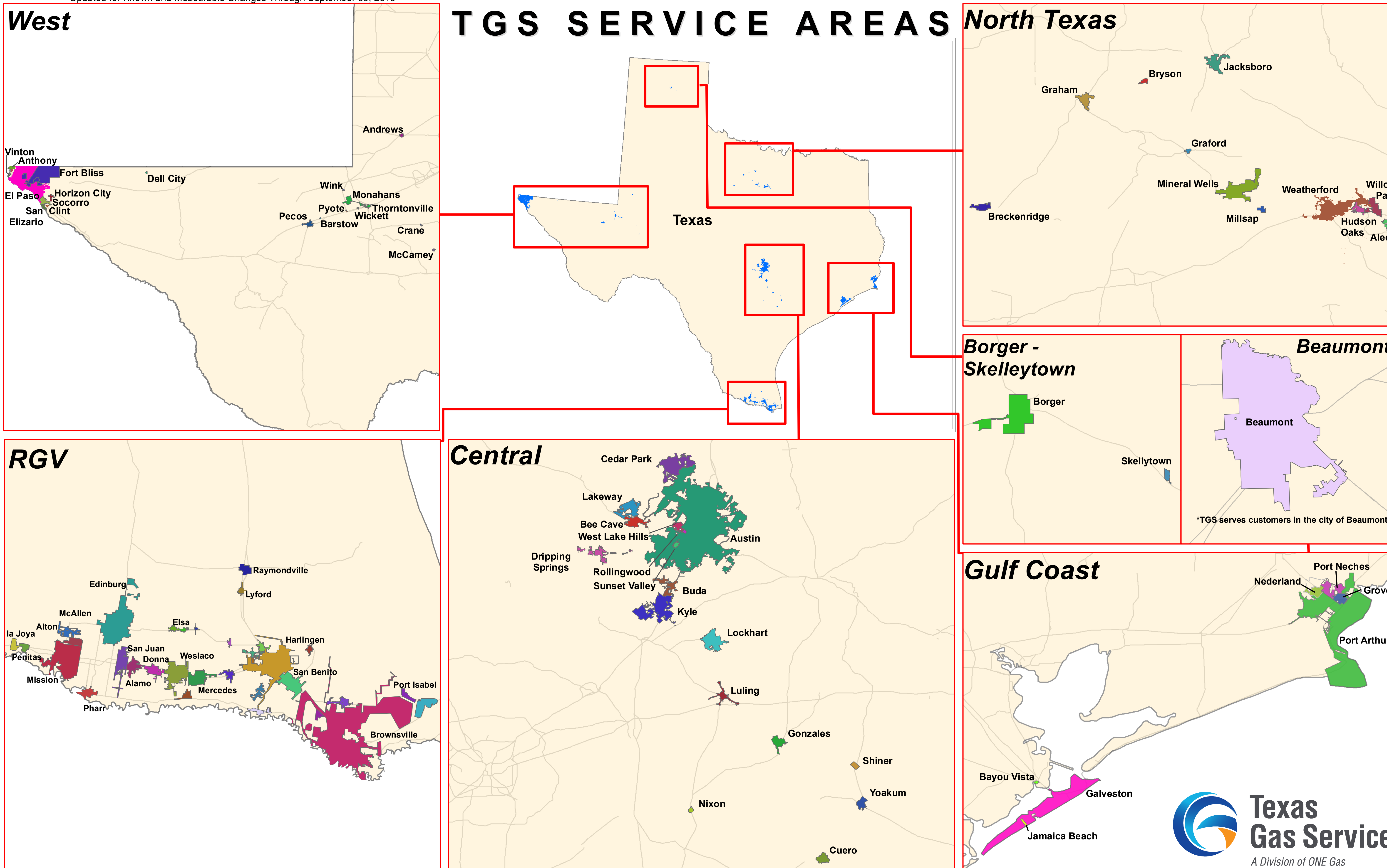

Exhibit SN-1
Page 1 of 1

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

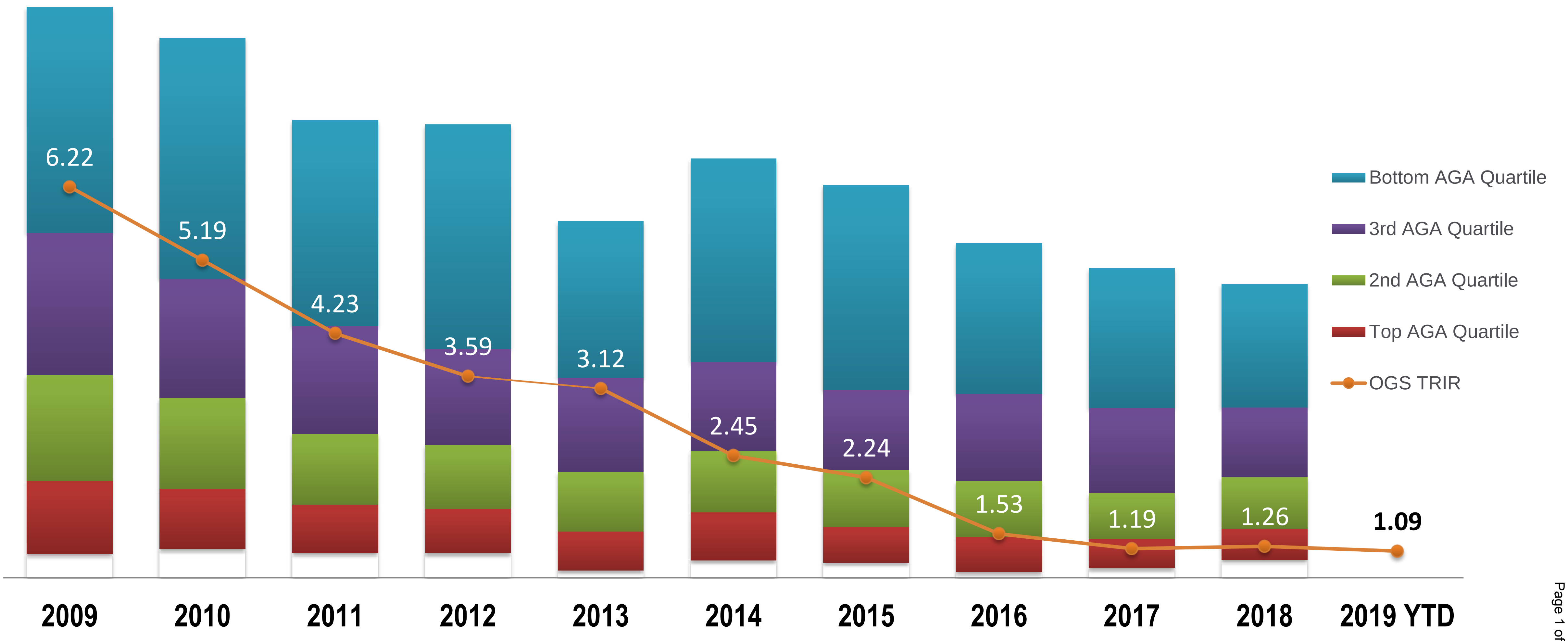

Exhibit SN-2
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AGA Days Away, Restricted and Transferred (DART) Quartile Compared to OGS DART

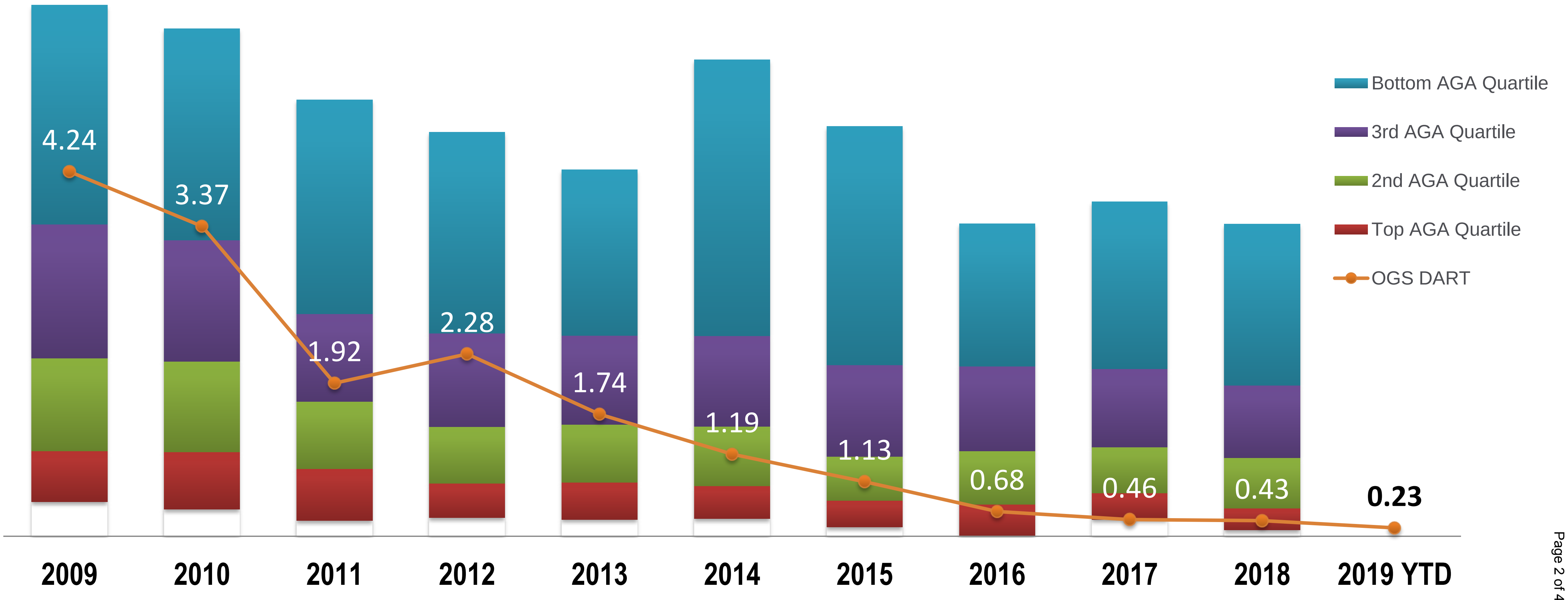

Exhibit SN-2
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AGA Preventable Vehicle Incident Rate (PVIR) Quartile Compared to OGS PVIR

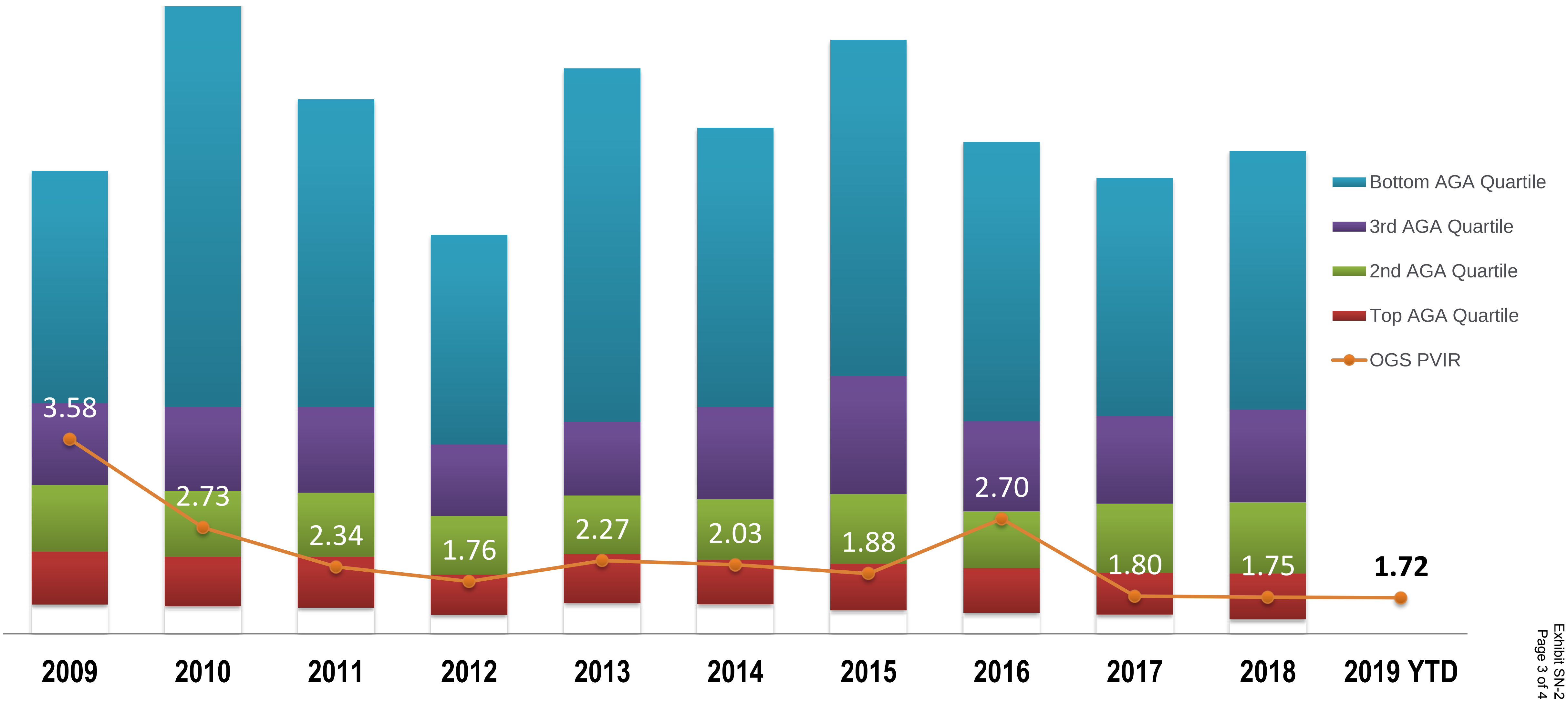

Exhibit SN-2
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Emergency Response Time: Percent of Onsite Times in Less than 30 Minutes – YTD 2019

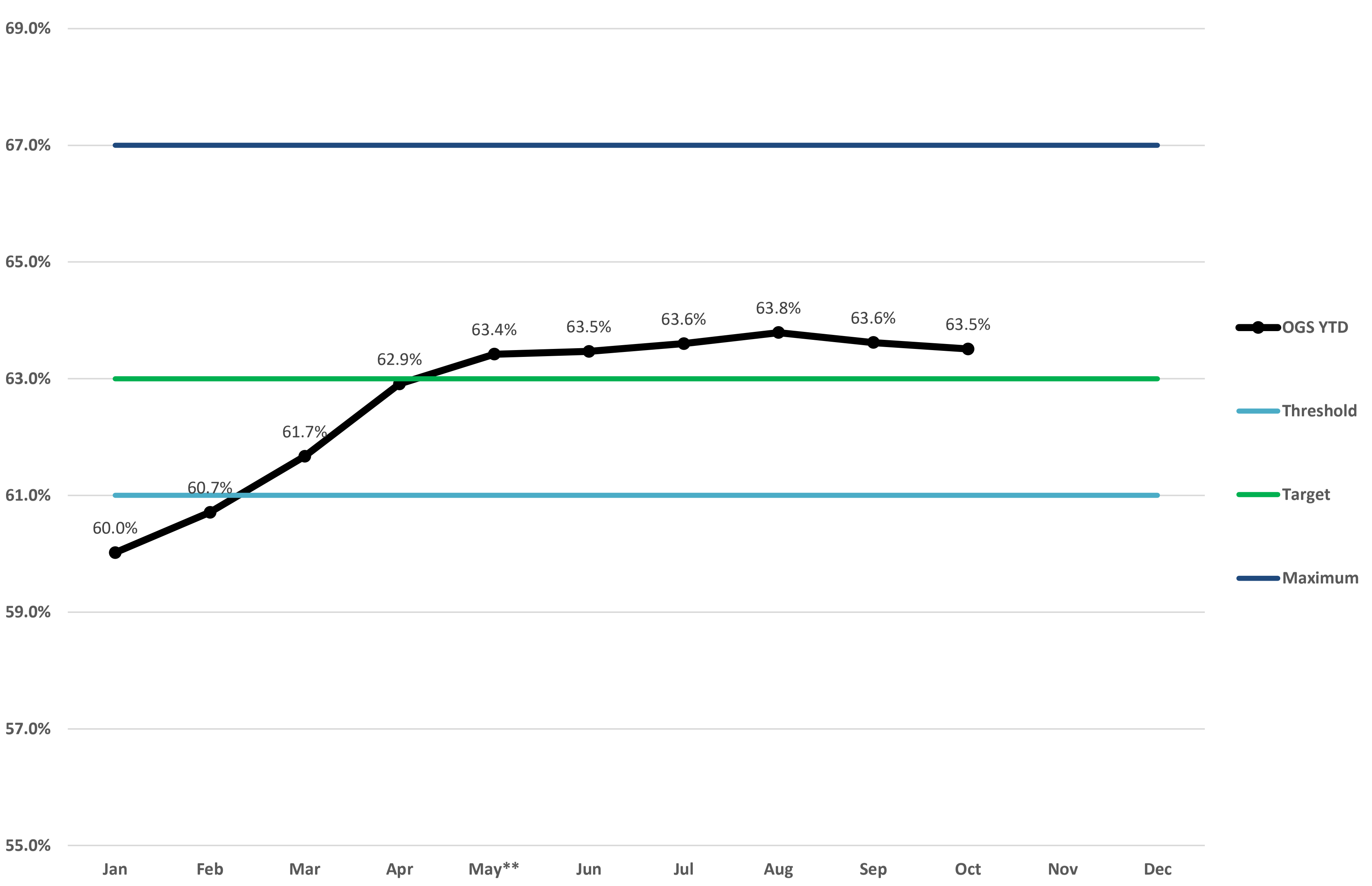

Exhibit SN-2
Page 4 of 4

Exhibits SN-3 and SN-4 are Voluminous
and will be provided electronically.

Year	**Total CGSA Net Adjusted Plant (Note 1)**	**Dollar Increase in Net Plant**	**Percentage Increase in Net Plant**
2015	$399,243,447		
2016	$436,556,463	$37,313,016	9.35%
2017	$466,026,977	$29,470,514	6.75%
2018	$510,085,351	$44,058,374	9.45%
Sept. 2019	$556,207,375	$46,122,024	9.04%
Total Increase from 2015 through Sept. 2019		$156,963,928	39.32%
Average Increase in Net Plant between 2015 through Sept. 2019		$39,240,982	8.65%

Note 1: Plant balances include Rule 8.209 regulatory assets through June 2019.

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 of 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.

Shantel Norman

Shantel Norman

SUBSCRIBED AND SWORN TO BEFORE ME by the said Shantel Norman on this 4 day of December, 2019

NATALIE L WOOLVERTON
Notary ID # 124048529
My Commission Expires
January 24, 2021

NOTARY PUBLIC
STATE OF TEXAS

N. L. Woolverton

Notary Public in and for the State of Texas

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

STACEY L. MCTAGGART

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF STACEY L. MCTAGGART

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stacey L. McTaggart, and my business address is 1301 South MoPac Expressway, Suite 400, Austin, Texas 78746.

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

A. I am the Rates and Regulatory Director for Texas Gas Service Company ("TGS" or the "Company"), 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.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

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

1. Consolidation of the existing Central Texas and Gulf Coast Service Areas ("CTSA" and "GCSA," respectively), as well as the City of Beaumont, Texas;
2. Request for a finding that ONE Gas' acquisition of the former ONEOK Transmission Company ("OTC") assets in June 2019, now held by ONE Gas Pipeline Company ("OPC"), is consistent with the public interest;
3. Transfer of the OPC assets into TGS's existing system;
4. The Company's compliance with certain regulatory and statutory requirements;

5. Affiliate cost recovery issues related to Utility Insurance Company ("UIC") and OPC;
6. The Company's compliance with the Accounting Order issued by the Commission in Gas Utilities Docket ("GUD") No. 10695 related to the federal Tax Cut and Jobs Act of 2017 (the "Act");
7. The Company's proposed EDIT Rider to return excess deferred income taxes ("EDIT") to customers;
8. Treatment of cloud-based computing costs in future filings;
9. TGS's recovery of costs associated with the Company's response to Hurricane Harvey;
10. The Company's recovery of pipeline integrity testing costs;
11. A proposed Natural Events Response Rider; and
12. The Company's recovery of rate case expenses.

Q. ARE YOU SPONSORING ANY COST OF SERVICE SCHEDULES?

A. No, I am not.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have filed testimony on behalf of TGS in numerous proceedings, including GUD Nos. 9770, 9790, 9839, 9988, 10094, 10453, 10488, 10506, 10526, 10656, 10739 and 10766.

II. CONSOLIDATION REQUEST

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING CONSOLIDATION OF SERVICE AREAS?

A. TGS proposes to consolidate two of its existing service areas, the CTSA and the GCSA, to form a new, combined service area called the Central-Gulf Service Area ("CGSA"). The Company also provides service to a few customers within the City of Beaumont and is seeking to include Beaumont in the proposed CGSA as well. As explained by Company witness Shantel Norman, this consolidation reflects operational realities already in place under the Company's functional operating model. Should the Company's request for consolidation not be approved, TGS requests at a minimum that the City of Beaumont be consolidated into the existing GCSA.

Q. IS THE COMPANY'S CONSOLIDATION PROPOSAL IN THIS FILING CONSISTENT WITH PRIOR COMMISSION APPROVALS OF CONSOLIDATION FOR TGS?

A. Yes, it is. Consolidation in this case is a natural continuation of the consolidation requests that the Commission has approved in recent cases for the Company and will result in system-wide rates for all customers in the proposed CGSA, which will avoid unreasonable rate differences between localities or between classes of service. In 2016, the Commission approved TGS's requests to consolidate service areas, which reduced the number of TGS service areas from ten to six. In GUD No. 10488, the Commission approved a unanimous settlement that included establishing the Company's existing GCSA, which was formerly 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 analyzing the request for consolidation in that case, the Administrative Law Judge noted in the Proposal for Decision that the proposed consolidation would result in system-wide rates for all customers in the proposed combined service area, which would avoid unreasonable rate differences between localities or between classes of service.[1] Finally, in GUD No. 10526, the Commission approved a unanimous settlement agreement in which the then-existing Central Texas and South Texas Service Areas were combined to establish the current Central Texas Service Area.

Q. WILL THERE BE ADMINISTRATIVE BENEFITS DERIVED FROM CONSOLIDATION?

A. Yes. Consolidation will lead to administrative efficiencies related to rate filings and tariffs. Specifically, consolidation will streamline and economize the Company's regulatory filings by reducing the number of cost-of-service analyses and rate cases the Company must file when it seeks to implement a change in rates within its service areas. The preparation of a rate filing package is a time- and resource-intensive effort. For example, prior to recent consolidations, the Company had to separately prepare rate filings for each of its ten service areas. By consolidating the service areas at issue in this case, the Company can prepare a single cost of service filing for regulatory review. This allows rate changes to be implemented uniformly and consistently, which is more economical and efficient

[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., First Amended Proposal for Decision at 12 (Sept. 16, 2016).

for the Company, customers and its regulators. In addition, by simplifying its rate filings, the Company may be able to reduce rate case expenses and allow cities within the separate service areas to pool their resources in order to reduce each municipality's individual expense to review each future filing. Finally, consolidation will reduce the number of tariffs administered by both the Company and the Company's regulators.

III. ONE GAS PIPELINE COMPANY

Q. WHAT ARE THE OPC-RELATED ISSUES TGS IS PRESENTING IN THIS FILING?

A. The Company requests that the Commission issue a finding that ONE Gas' purchase of OTC and its assets on June 30, 2019 is consistent with the public interest. The Company also seeks a finding that it is not necessary to include in rate base the negative acquisition adjustment associated with the purchase. Finally, the Company demonstrates that the known and measurable adjustments to TGS's test year cost of service for OPC-related costs comply with the standard in the Gas Utility Regulatory Act ("GURA") for affiliate costs, to the extent the standard applies.

Q. WAS THE COMMISSION NOTIFIED OF ONE GAS' ACQUISITION OF THE OTC PIPELINE AS REQUIRED BY TEXAS UTILITIES CODE SECTION 102.051?

A. Yes. On July 19, 2019, ONE Gas filed a notification letter with the Commission, which was docketed as GUD No. 10877 to report the acquisition in compliance with Section 102.051. In the letter, ONE Gas informed the Commission that under ONE Gas ownership, the acquired pipeline system is now ONE Gas Pipeline

Company, L.L.C.. On October 9, 2019, TGS received a letter from the Commission indicating its review of the transaction was complete and the related public interest issues would be addressed in this next rate case. A copy of the Company's notification letter to the Commission, as well as the Commission's acknowledgment of its review of the transaction is attached as Exhibit SLM-1. I also provide the Company's responses to Commission-issued discovery in that docket in my direct testimony workpapers.

Q. PLEASE DESCRIBE THE OPC ASSETS.

A. The OPC assets consist of a natural gas pipeline system extending from Kyle, Texas to Cuero, Texas, and connect TGS's distribution system in the area to transmission pipelines. The OPC line and the TGS distribution lines in the area form a closed system. That is, all gas consumed by TGS customers in the area is first shipped on the OPC line, and all gas shipped on the OPC line is consumed by TGS customers. No gas shipped on the OPC line leaves TGS's system.

Q. WHO OPERATES THE OPC LINE?

A. Previously, under OTC ownership, TGS operated the line pursuant to an operating agreement between TGS and OTC. Currently, under OPC ownership, TGS continues to operate the line under the operating agreement that existed with OTC. TGS has no dedicated employees for this purpose. Instead, the line is operated by TGS distribution employees as part of TGS's overall operations in the area. Employees charge labor and materials associated with the operation of the line to a specified OPC cost center in order to track expenses associated with the line. OPC pays TGS monthly for the operation of the line, and TGS records the payment as an offset to the expenses. In this way, TGS is reimbursed for the expenses to operate the line, and no costs associated with the line are currently included in the CTSA cost of service or in CTSA base rates.

Q. PLEASE DESCRIBE THE SERVICE PROVIDED ON THE PIPELINE.

A. OPC transports gas for TGS on behalf of TGS's gas sales customers from transmission pipeline interconnects to a number of TGS town border stations. TGS pays OPC for this transportation service and includes the cost in the monthly cost of gas charged to TGS gas sales customers through the Cost of Gas Clause. In addition, OPC transports gas from transmission pipeline interconnects to ten end users, all located on the TGS system. The ten end users pay OPC to transport gas to the TGS town border stations and pay TGS to transport the gas from the town border stations to the end user's location. Seven of the end users pay TGS's standard tariff transportation rates, and three of the end-users pay negotiated rates under GURA § 104.003(b). OPC has no end-use customers outside the TGS town border stations.

Q. WHAT WERE THE CHARGES FOR TRANSPORTATION SERVICE ON THE OPC LINE DURING THE TEST YEAR?

A. During the test year, TGS paid $676,658 for transportation on behalf of its gas sales customers. ONEOK retains OTC's billing records for the ten end-users during the test year. However, TGS reviewed OTC's annual income statement and determined that the ten end-users paid an average of $481,090 annually for transportation on the line. During the test year, these fees were paid to OTC pursuant to contracts between OTC and the shippers. After June 30, 2019, when ONE Gas acquired OTC, the contracts were assigned to OPC, and OPC has continued to charge shippers the same rates under the same contracts the shippers had with OTC.

Exhibit SLM-2 shows monthly payments to OTC/OPC from TGS and annual payments from all end-use shippers for the test year and the months subsequent to the test year.

Q. IS THE PURCHASE OF THE ASSETS CONSISTENT WITH THE PUBLIC INTEREST?

A. Yes, ONE Gas' purchase of the assets is consistent with the public interest because the operation of the pipeline and the customers' service and rates were unaffected. In addition, operation and maintenance of the pipeline will be streamlined by having the same entity operate and own the line, once the line is fully incorporated into TGS's existing system at the conclusion of this rate case. The transfer of assets and operations has been seamless. There has been no change in personnel operating the system, no change in service to the customers, and no change in rates to the customers. The assets were recorded on TGS's books at the original cost and accumulated depreciation amount on the seller's books. Further, the acquisition has had no impact on TGS's or OPC's existing obligations, and both companies continue to meet all statutory and regulatory obligations and to comply with applicable Commission rules regarding their books and records and other regulatory requirements. Finally, as a result of this transaction, the OPC assets, which have long been operated by TGS are now under ONE Gas' management. Consequently, the Company is better positioned to ensure the continued safe and reliable operation of the assets and continued access to gas supply for TGS's gas sales customers.

Q. DOES ONE GAS INTEND FOR OPC TO CONTINUE TO OWN THE PIPELINE?

A. No, at the conclusion of this case, ONE Gas intends to transfer the OPC assets to TGS for incorporation into TGS's existing distribution system ("the transfer of assets" or "the transfer").

Q. WHAT IS EXPECTED TO HAPPEN REGARDING THE OPC TRANSPORTATION CONTRACTS WITH TGS AND THE TEN END-USE SHIPPERS ("OPC CONTRACTS") AFTER THE TRANSFER OF ASSETS?

A. After the transfer, OPC will be dissolved and the contracts will be assigned to TGS. The Company is recommending that these contracts be terminated in the best interest of the customers. As explained previously, all OPC end-use customers are also TGS customers. The ten end-users have existing contracts to transport gas on TGS's system ("TGS Contracts"). When the OPC assets are incorporated into the existing TGS distribution system, transportation on the OPC line will be covered under the TGS contracts, and the OPC Contracts will become redundant. The end users will likely recognize the redundancy and seek to terminate the unnecessary OPC Contracts. The Company recommends termination of these contracts whether or not the end users request termination. Finally, the OPC Contract with TGS to transport gas on behalf of TGS sales customers is recommended to be terminated, because it does not make sense for TGS to charge itself for the transportation of gas.

Q. IF ALL CONTRACTS ASSOCIATED WITH THE OPC LINE ARE TERMINATED, WHAT REVENUE WILL SUPPORT THE CAPITAL AND EXPENSES ASSOCIATED WITH THE OPC LINE THAT WILL BECOME PART OF TGS'S EXISTING SYSTEM?

A. After transfer of the assets at the conclusion of this case, the OPC assets will be included in TGS's rate base. The operations and maintenance ("O&M") expense associated with the assets will be a TGS expense. The rate base and expense will be part of TGS's cost of service and will be allocated among TGS's classes of customers as part of the class cost of service study, ultimately becoming part of TGS's base rates. Right now, the TGS gas sales customers pay for transportation on the OPC line through the monthly cost of gas charge. Once the OPC assets are transferred to the TGS distribution system, the cost of gas charge will be eliminated, and TGS base sales rates will increase due to the inclusion of OPC assets and expenses in TGS's cost of service. Similarly, the end-use transportation customers currently pay a fee to OPC for transportation on the OPC line and a fee to TGS for transportation on TGS lines. Subsequent to the transfer, the fee to OPC will be eliminated and the TGS base transportation rates will increase due to the inclusion of OPC assets and expenses in TGS's cost of service.

Q. HAS TGS INCLUDED THE OPC ASSETS AND EXPENSES IN ITS COST OF SERVICE IN THIS FILING?

A. Yes, amounts for OPC assets and expenses are included as known and measurable adjustments to TGS's test year costs. Company witness Gracie Guerra sponsors the inclusion of the assets in rate base, and Company witness Marie J. Michels sponsors the inclusion of OPC expenses in O&M expense. Because ONE Gas intends to transfer the OPC assets to TGS at the conclusion of this case, TGS has designed the cost of service to reflect that intention by including the OPC assets and expenses in its cost of service in this case, and therefore it is important that the transfer of assets and the implementation of new base rates occur simultaneously. At the conclusion of the case, the assets will be transferred, the OPC Contracts are recommended to be terminated, and TGS will begin charging the newly approved base sales and transportation rates.

Q. WHAT AMOUNT OF EXPENSES ASSOCIATED WITH OPC HAS TGS INCLUDED IN ITS COST OF SERVICE IN THIS FILING?

A. As discussed by Ms. Michels, TGS has included $283,146 in O&M expense as shown on Workpaper G.a.2. This is equal to the amount of expenses incurred by TGS as the operator of the line during the test year. In addition, TGS has included $148,277 in annual depreciation expense as shown on Workpaper G-15.a. Finally, the OPC assets are included in the calculation of ad valorem taxes shown on Schedule G-16, resulting in $43,434 of ad valorem tax associated with the OPC assets.

Q. WHAT AMOUNT OF CAPITAL ASSOCIATED WITH OPC HAS TGS INCLUDED IN ITS COST OF SERVICE IN THIS FILING?

A. As discussed in the testimony of Ms. Guerra, TGS included the OPC assets in rate base at their original cost less accumulated depreciation on the books of the seller. The original cost of the assets on OTC’s books at June 30, 2019 was $8,024,125. The accumulated depreciation on OTC’s books at June 30, 2019 was $2,973,659. The resulting net plant included in rate base is $5,050,466.

Q. HAS TGS INCLUDED ANY REVENUE ADJUSTMENTS ASSOCIATED WITH THE OPC ASSETS IN ITS COST OF SERVICE IN THIS FILING?

A. Yes. While TGS did not include any actual OPC revenues in this filing because the OPC contracts will be terminated upon the transfer of the assets to TGS, a proforma adjustment was made to TGS transportation revenues to reflect the application of standard transportation rates to test year billing determinants for the end-use transportation customers. Company witness Janet L. Buchanan addresses this adjustment in her direct testimony.

Q. WHAT IS THE OVERALL IMPACT TO CUSTOMERS AS A RESULT OF THE INCLUSION OF THE OPC ASSETS AND EXPENSES IN THE COST OF SERVICE?

A. As shown on Exhibit SLM-3, the TGS cost of service is increased by $958,692 as a result of the inclusion of the OPC assets and expenses. As shown on Exhibit SLM-2, adding the revenues TGS paid to OTC during the Test Year and the annual average revenues other customers paid to OTC, the total revenues paid to OTC were approximately $1,157,800. This amount is $199,056 more than the cost customers will experience as a result of including the OPC assets and expenses in TGS's cost of service in this case. In other words, the acquisition of OTC assets and subsequent transfer of the assets to TGS results in a reduction in cost to gas sales and end-use transportation customers. This also supports the request for a finding that ONE Gas' acquisition of the OTC assets is consistent with the public interest.

Q. HAS TGS INCLUDED ANY REVENUE ADJUSTMENTS ASSOCIATED WITH THE OPC ASSETS IN ITS COST OF SERVICE IN THIS FILING?

A. Yes. While TGS did not include any OPC revenues in this filing because the OPC contracts will be terminated upon the transfer of the assets to TGS, a proforma adjustment was made to TGS transportation revenues to reflect the application of standard transportation rates to test year billing determinants for the end-use transportation customers. Ms. Buchanan addresses this adjustment in her direct testimony.

Q. WHAT PRICE DID ONE GAS PAY FOR THE OTC ASSETS?

A. The purchase price of the OTC assets was $2,568,952, giving rise to a $2,531,514 negative acquisition adjustment.

Q. HAS TGS INCLUDED THE NEGATIVE ACQUISITION ADJUSTMENT IN ITS RATE BASE IN THIS FILING?

A. No. TGS has included the OPC plant in rate base at its original cost less accumulated depreciation and has not reflected the negative acquisition adjustment in either the plant balances or rate base.

Q. WHY IS TGS'S PROPOSED TREATMENT OF THE NEGATIVE ACQUISITION ADJUSTMENT APPROPRIATE?

A. It is appropriate to exclude the negative acquisition adjustment from rate base because this treatment is consistent with the treatment typically afforded positive acquisition adjustments. In the event of an acquisition, the Commission's practice has been to require the acquiring utility to include the plant in rate base at its original cost at the time the plant was placed into utility service less accumulated depreciation. The Commission has typically not allowed an acquisition premium to be included in rate base. For example, TGS carries a $106 million acquisition premium on its books, dating to 2003, arising from TGS's acquisition of the Texas assets of Southern Union Gas Company. TGS has never been authorized to include this acquisition premium in rate base or to earn a return on the acquisition premium. The exclusion of the negative acquisition adjustment from rate base in this case would simply provide a small offset to the larger acquisition premium that is also excluded from rate base. In addition, as previously explained, the inclusion of the OPC assets in the cost of service without the negative acquisition adjustment increases the cost of service by $958,692 which is $199,056 less than the revenues paid by OTC customers during the test year. Even without the reduction to rate base of the negative acquisition adjustment, the customers will be paying less than they did prior to the acquisition. Furthermore, ONE Gas's financial ability and expertise in operating distribution systems combined with the integration of this system into existing TGS systems make the acquisition a natural fit and will result in more efficient operation of the system. Last, the acquisition results in in-state ownership of the pipeline, and results in no negative impacts to service standards or regulatory jurisdiction.

Q. HAS TGS PROPOSED THE EXCLUSION OF A NEGATIVE ACQUISITION ADJUSTMENT FROM RATE BASE IN ANY PRIOR PROCEEDINGS?

A. Yes. On November 7, 2003, TGS Rio, LLC reported the acquisition of pipeline systems from GulfTerra Pipeline, L.P. to the Commission.[2] The pipeline assets had

[2] *Application of TGS Rio, LLC for Review of the Purchase of Certain Pipeline Systems from GulfTerra Texas Pipeline, L.P,* GUD No. 9466.

a net book value of $4.4 million with a purchase price of $3.6 million, giving rise to a $830,576 negative acquisition adjustment. On March 30, 2006, TGS filed a rate case with the Rio Grande Valley cities in which TGS proposed to include the acquired Rio Pipeline assets in rate base at original cost less accumulated depreciation, and not include the negative acquisition adjustment in rate base. The cities argued in favor of recognizing the negative acquisition adjustment in rate base, but the case was ultimately settled by the parties. The settlement agreement did not specifically address the treatment of the negative acquisition adjustment. On November 17, 2006, TGS filed a statement of intent at the Commission to implement the settled incorporated rates in the environs. In GUD No. 9708, the Commission approved the requested rates for environs customers.[3]

IV. COMPLIANCE WITH COMMISSION RULES AND AFFILIATE STANDARD

A. Commission Rules §§ 7.310 and 7.503

Q. PLEASE SUMMARIZE HOW THE BOOKS AND RECORDS OF TGS ARE MAINTAINED AND UTILIZED IN THE REGULAR COURSE OF BUSINESS.

A. TGS maintains its books and records in accordance with Commission Rule § 7.310, which requires that the Company keep its books in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA"), as supplemented by Commission order or State law. The FERC USOA is prescribed by the FERC for public utilities and licensees subject to the provisions

[3] *Statement of Intent Filed by Texas Gas Service Company to Change Rates in the Environs of the Rio Grande Valley Service Area*¸ GUD No. 9708, Final Order at 5 (Apr. 11, 2007).

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 2019 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. In addition, ONE Gas has disclosed that in the three months ended March 31, 2019, it implemented new internal controls over lease accounting related to the adoption of the Financial Accounting Standards Board's ("FASB") Accounting Standard's Codification Topic 842, "Leases." The implementation of these new controls is part of ONE Gas' continuing efforts to ensure compliance with the new FASB requirements. ONE Gas disclosed that it does not believe the implementation of the new controls materially affected, or is reasonably likely to materially affect, its internal control over financial reporting and that other than the new lease accounting controls, there have been no changes in ONE Gas' internal control over financial reporting during the three months ended March 31, 2019, that have materially affected, or are reasonably likely to materially affect, its internal control 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 framework in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In connection with the evaluation, ONE Gas' Internal Audit Department annually reviews the design and 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 20, 2019. The report concluded that our disclosure controls and procedures and our internal control over financial reporting were effective at December 31, 2018. 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 20, 2019. 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, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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 CGSA, and no such profits or losses are included in the Company's cost of service.

Q. PLEASE STATE THE AMOUNT OF INCOME TAX SAVINGS OR DEFERRALS, AS REQUIRED BY COMMISSION RULE § 7.501(2).

A. The amount of accumulated deferred income taxes ("ADIT") applicable to the proposed CGSA is a negative $(80,421,556) as shown on Schedule B-8 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 CGSA 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 CGSA includes $37,109 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 UTILITY INSURANCE COMPANY 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, TGS now has affiliate costs subject to review under the statutory affiliate standard. The testimony of Company witness Mark W. Smith provides a detailed explanation of UIC, and Company witnesses Mindy R. Edwards and Anthony Brown support the schedules that reflect TGS's test year UIC costs. In addition, upon the closing of the transaction through which ONE Gas acquired the assets of OTC, ONE Gas created an affiliate, OPC, to own the asset. There are no test year per book costs related to OPC, but TGS has made known and measurable changes to adjusted test year costs for OPC-related capital investment and expenses, which are addressed by Ms. Guerra and Ms. Michels.

Q. PLEASE DESCRIBE THE COMMISSION'S AFFILIATE STANDARD.

A. Under Texas Utilities Code § 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 and 10766, which were resolved through settlement agreements approved by the Commission.

Q. DID ANY AFFILIATE TRANSACTIONS OCCUR DURING THE TEST YEAR BETWEEN OPC AND TGS?

A. No affiliate transactions occurred during the test year, because OPC did not become an affiliate until June 30, 2019, which is the end of the test year.

Q. DID ANY AFFILIATE TRANSACTIONS OCCUR DURING THE TEST YEAR BETWEEN OPC AND ANY OTHER ONE GAS ENTITY?

A. No. OPC does not provide service to any ONE Gas entity other than TGS. It does, however, provide service to non-affiliated entities under negotiated arms-length contracts. When ONE Gas acquired OTC, neither TGS's existing contract nor the existing contracts with non-affiliated entities changed. They were simply assigned from OTC to OPC. Costs for these transactions are not included in the costs TGS seeks to recover through new rates for the proposed CGSA. Instead, TGS plans to incorporate the OPC line into TGS's existing system, where it is currently used to provide service between Kyle and Cuero, Texas.

Q. DID ANY AFFILIATE TRANSACTIONS OCCUR AFTER THE TEST YEAR BETWEEN OPC AND TGS?

A. Subsequent to the end of the test year, two affiliate transactions exist. First, OPC reimburses TGS for the expenses that TGS incurs to operate and maintain the pipeline based on a negotiated arms-length contract with the prior owner of the OPC assets. TGS utilizes existing TGS employees to operate the line and records the costs without mark up. Thus, TGS operates and maintains the OPC assets at the same cost level as it operates and maintains its own assets. Second, during the test year, TGS paid OTC $676,658 for transportation of gas for TGS system sales customers. These reasonable and necessary gas transportation costs are the result of an arms-length negotiation with the prior owner of the OPC assets. These costs are not reflected in the cost of service schedules because gas transportation costs are recovered under the Company's cost of gas clause and are not included in base rates.

Q. PLEASE DESCRIBE THE OPC-RELATED COSTS THAT ARE BEING USED TO DETERMINE KNOWN AND MEASURABLE ADJUSTMENTS TO TEST YEAR COSTS.

A. As an initial matter, TGS is not requesting to recover any costs paid to OPC through rates. Therefore, it appears that the affiliate standard does not apply to OPC-related costs. Instead, TGS is using post-test year costs related to OPC to determine adjustments to the Company's test year capital, expense and revenue amounts. Because TGS is relying on affiliate costs to determine these adjustments, out of an abundance of caution, it is presenting evidence related to compliance with the affiliate standard.

As previously discussed, to properly reflect the costs of incorporating the OPC line into TGS's system, the Company made the following known and measurable adjustments to test year costs:

- an adjustment to expense to include costs for TGS's operation and maintenance of the OPC assets; the adjustment is based on costs TGS billed to OTC before ONE Gas acquired the assets. Ms. Michels sponsors the schedule that reflects this adjustment.
- an adjustment to rate base to include capital costs for the OPC line; the adjustment is based on the net book value of the OPC assets. Ms. Guerra

sponsors the schedule that reflects this adjustment. Ms. Michels sponsors the schedules that reflect the associated depreciation and ad valorem taxes.

- an adjustment to revenues based on imputing revenue based on TGS standard tariff transportation rates to three TGS customers currently paying negotiated rates. This adjustment is not based on OPC revenues, but occurs as a result of the OPC acquisition. Ms. Buchanan sponsors the schedule that reflects this adjustment.

Q. IF THE AFFILIATE STANDARD WERE APPLIED, DO THE OPC-RELATED ADJUSTMENTS TO TEST YEAR COSTS COMPLY WITH THE AFFILIATE STANDARD IN GURA?

A. Yes. First, the costs charged by OPC to TGS are reasonable and necessary and not higher than the price charged by OPC to unaffiliated entities for the same item or service. Second, the OPC-related adjustments reflect costs that comply with the affiliate requirements because all of the adjustments are based on transactions between TGS and OTC--the prior entity that was not owned by an affiliate. In addition, as I noted above, the contracts between TGS and OTC were assigned to OPC as part of the acquisition. So, the costs of the transactions between TGS and OTC were the result of arms-length negotiated agreements.

V. <u>FEDERAL TAX CUT AND JOBS ACT OF 2017</u>

Q. PLEASE EXPLAIN THE CHANGES TO THE FEDERAL CORPORATE INCOME TAX RATE THAT BECAME EFFECTIVE IN 2018.

A. Effective January 1, 2018, the Act lowered the federal corporate income tax rate to 21% from 35%. In response, the Commission issued an Accounting Order in GUD No. 10695 on February 27, 2018, that reflects the Commission's directives regarding changes to utility rates to account for the change in the federal corporate income tax rate.[4]

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 statement of intent 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 CTSA AND GCSA?

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 CTSA and the environs area of the GCSA 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 rates or new GRIP rates that reflect

[4] On March 20, 2018, the Commission issued an Order Nunc Pro Tunc in GUD No. 10695, correcting a clerical error in the original Accounting Order.

the 21% federal tax rate (Ordering Paragraph 3). TGS was required to file either a Statement of Intent 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.

Q. HOW DID THE COMPANY REDUCE EXISTING BASE RATES AND GRIP RATES FOR THE CTSA INCORPORATED CUSTOMERS?

A. On March 26, 2018, the Company made a filing with the CTSA 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 CTSA cities. Effective June 26, 2018, TGS reduced rates by $4,365,407. In addition, TGS refunded $9.66 per customer, totaling $2,248,798, to account for the tax rate reduction from January 1, 2018 through June 26, 2018.

Q. HOW DID THE COMPANY REDUCE EXISTING BASE RATES AND GRIP RATES FOR THE CTSA 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. 10526 and in GUD No. 10610 and to issue a refund to customers within the CTSA environs, which the Commission docketed as GUD No. 10714. Effective June 26, 2018, TGS reduced rates by $537,293. In addition, TGS refunded $9.66 per customer, totaling $202,552, 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 GCSA ENVIRONS?

A. On April 27, 2018, the Company made a filing with the Commission under GURA § 104.111 to lower existing rates set in GUD No. 10488 and to issue a refund to customers within the GCSA environs, which the Commission docketed as GUD No. 10730. Effective May 25, 2018, TGS reduced rates by $21,989. In addition, TGS refunded $8.75 per customer, totaling $10,590, to account for the tax rate reduction from January 1, 2018 through May 25, 2018.

Q. HOW DID THE COMPANY REDUCE BASE RATES IN THE GCSA INCORPORATED AREA TO ACCOUNT FOR THE CHANGE IN THE FEDERAL TAX RATE?

A. On April 27, 2018, the Company made an annual filing with the GCSA cities under its existing GCSA Cost of Service Adjustment tariff to reflect changes in capital investment and operating and maintenance expenses and incorporating the 21% tax rate. The filing resulted in a reduction in rates of $797,127 for customers within the GCSA cities, effective July 26, 2018. In addition, TGS refunded $12.72 per customer, totaling $555,995, to account for the tax rate reduction from January 1, 2018 through July 26, 2018.

Q. HAS THE COMPANY COMPLETED THE REQUIRED REFUNDS TO CUSTOMERS IN THE CTSA AND GCSA?

A. Yes. All required refunds were completed in 2018, consistent with the requirements of the Accounting Order.

Q. DID TGS MAKE A FILING WITH THE CITY OF BEAUMONT TO CHANGE RATES FOR THE LOWER FEDERAL INCOME TAX RATE?

A. No. TGS made an initial rate filing with the City of Beaumont on May 22, 2019 with rates that already reflected a 21% federal income tax rate. Customers within the City of Beaumont did receive a refund in the same amount per customer as customers in incorporated areas of the GCSA.

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 statement of intent or other rate proceeding." In addition, the amortization of the entire regulatory liability for EDIT shall be consistently calculated using a methodology set forth under the Act (Ordering Paragraph 7).

Q. PLEASE DESCRIBE HOW ADIT IS INCLUDED IN THE STATEMENT OF INTENT, INCLUDING HOW TGS IS PRESENTING EDIT FOR CONSIDERATION IN SETTING NEW RATES.

A. The statement of intent reflects 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 are deducted from rate base as sources of cost-free capital. Ms. Simpson addresses the ADIT calculations in her testimony.

For EDIT, the Company proposes to flow the EDIT back to customers through a separate tariff rider, Rate Schedule EDIT-Rider, calculated according to the Average Rate Assumption Method ("ARAM"). Company witness Jeffrey J. Husen explains in his direct testimony that using ARAM is a methodology set forth under the Act, as required by Ordering Paragraph 7 in the Commission's Accounting Order.

Q. WHY DOES THE COMPANY PROPOSE TO FLOW THE EDIT BACK TO CUSTOMERS THROUGH A RIDER?

A. The Company proposes to flow the EDIT back to customers through a separate rider instead of through base rates because, under ARAM, the amount of the amortization will vary from year to year. Because base rates are typically set for a number of years, it would be difficult to determine the amount of EDIT flow back to include in base rates. Including the flow back in a separate rider provides the ability to flow back a different amount each year and to track the flow back of EDIT to ensure that customers are credited the correct amount in full.

Q. WHAT IS THE AMOUNT OF THE AMORTIZATION TO BE FLOWED BACK THROUGH THE EDIT RIDER DURING THE FIRST YEAR?

A. The first year's EDIT amortization is $1,286,160. If approved, the Company will apply the credit to customer bills in 2020.

Q. HOW WILL THE EDIT FLOW BACK BE ADDRESSED AFTER THE FIRST YEAR?

A. In late 2020, the Company will true up the first year's EDIT amortization credits. The resulting true-up amount will be added to the second year's EDIT amortization to calculate the second year's credit per customer, which will be applied to customer bills in 2021. The Company will continue making annual calculations and annual true-ups in the same fashion until the full amount of the EDIT is amortized and credited back to customers.

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 GCSA and CTSA Section 104.111 environs filings were reasonable and accurate.

VI. CLOUD COMPUTING SERVICE COSTS

Q. WHAT IS THE COMPANY'S REQUEST REGARDING CLOUD COMPUTING IMPLEMENTATION COSTS?

A. The Company requests to recover capitalized cloud computing implementation costs, including setup and other upfront costs recorded on the Company's books, as reasonable and necessary investment in this case. In addition, due to a change in accounting standards, the Company is requesting authorization to include capitalized cloud computing implementation costs as investment in future rate filings, including Gas Reliability Infrastructure Program ("GRIP") filings. The Company also seeks authorization to amortize cloud computing implementation costs over the same depreciable life as on-premise software in order to maintain consistency in regulatory treatment and not increase annual expenses that are ultimately paid by the customer.

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 (CRM), 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. Simplifies recovery in the event of a major problem with ONE Gas' IT environment.
4. Improves scalability when applications need more resources without having to buy additional hardware.

5. Improved accessibility, which allows employees access to information on a variety of devices.

Q. HOW ARE CLOUD COMPUTING COSTS RECORDED ON THE COMPANY'S BOOKS AND RECORDS?

A. The Company currently includes cloud computing implementation costs as Corporate capital investment, in Account 391.6 for Purchased Software, and that balance is amortized over 13 years. In contrast, the annual cloud computing license or subscription costs are recorded as a prepayment in Account 165, and the cloud computing implementation costs are expensed over the life of the service agreement.

Q. WHAT AMOUNTS OF CLOUD COMPUTING IMPLEMENTATION COSTS HAVE THE COMPANY RECORDED AS CORPORATE INVESTMENTS?

A. The amounts of cloud computing implementation costs included in the Corporate asset Account 391.6 Purchased Software are summarized in the table below, which also shows the amount of costs that are currently in construction work in progress ("CWIP").

2016	2017	2018	2019	Current CWIP
$45,406	$0	$466,953	$222,769	$3,519,279

These costs are allocated using the Corporate Allocation methodology, which Mr. Brown discusses in his testimony. Also, Ms. Mindy Edwards supports Corporate rate base adjustments and depreciation expense, using the cost allocation methodology and calculations that are discussed in Mr. Brown's testimony.

Q. PLEASE DESCRIBE THE PROJECTS THAT ARE CURRENTLY IN CWIP.

A. The large investment that is currently included in Corporate CWIP is primarily made up of two projects, SharePoint O365 Online ("SPO") and Next Generation Payroll. The SPO platform is necessary to support the new company intranet (ONEGas Hub) and other customized SharePoint team sites that ONE Gas and TGS regularly use to manage work product and processes in an efficient manner given that employees work in different locations throughout ONE Gas. The new SPO will provide users with a more intuitive SharePoint experience, and improve efficiency and productivity. Next Generation Payroll is the implementation of a time entry and payroll solution for ONE Gas. The primary goals of this project include: (1) elimination of manual processes in the back office and avoiding penalties, (2) validating existing payroll requirements to ensure that the current or new system can accommodate those requirements, (3) implementing a time entry system that interfaces with existing electronic systems, and (4) providing flexible options for employees to enter time (e.g., time clocks and smart phone interfaces).

Q. DOES THE COMPANY EXPECT INVESTMENTS IN CLOUD COMPUTING TO CONTINUE IN THE FUTURE?

A. Yes, it does. As shown in the above table, the Company has $3.5 million of cloud computing implementation costs in CWIP. As another example, the Company's Enterprise Resource Planning ("ERP") and customer service applications are two of the largest and most expensive on-premise software applications. These applications are between 15 and 20 years old and will need to be replaced in the future. Currently, leading ERP software vendors are transitioning to cloud-only offerings.

Q. ARE THERE ANY RECENT ACCOUNTING CHANGES TO CLOUD COMPUTING THAT IMPACT RECOVERY IN RATES?

A. Yes. Accounting Standards Update 2018-15[5] ("ASU") published by FASB in 2018 requires that after December 15, 2019, cloud computing implementation costs be capitalized and recorded as "Other Assets" and amortized over the term of the hosting agreement with the cloud computing service, which is typically 3 to 5 years.

Q. DO THE CHANGES IN THE ACCOUNTING STANDARD IMPACT FUTURE FILINGS?

A. Yes. The impact to future filings is prospective because ASU 2018-15 does not take effect until calendar year 2020. There are two different impacts from ASU 2018-15. First, cloud computing implementation costs are currently included in Account 391.6 Purchased Software. The new standard requires these capitalized implementation costs to be recorded as an "Other Asset," Account 186, and the change in this account is not generally included in GRIP filings. TGS is requesting authorization for regulatory purposes to continue to include cloud computing implementation investment in future rate filings, including annual GRIP filings, as an intangible asset. Second, this investment is currently amortized over the same life as on-premise software, which is 13 years. The new standard requires these capitalized implementation costs to be amortized over the term of the hosting arrangement, including renewal periods. This change results in amortizing these

[5] https://asc.fasb.org/imageRoot/22/118236022.pdf.

costs over a period of 3 to 5 years as opposed to amortizing over a 13-year life, which increases annual expenses. 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.

Q. ARE CAPITALIZED CLOUD COMPUTING IMPLEMENTATION COSTS APPROPRIATE TO INCLUDE IN THIS FILING AND FUTURE FILINGS?

A. Yes. These costs are reasonable and necessary amounts to include in rate base in this case. It is also reasonable for TGS to include the change in investment in future GRIP filings and rate cases because the nature of these investments have 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 CGSA. Additionally, the National Association of Regulated Utility Commissioners ("NARUC") issued a November 2016 resolution[6] 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.

[6] https://pubs.naruc.org/pub.cfm?id=2E54C6FF-FEE9-5368-21AB-638C00554476.

VII. HURRICANE HARVEY

Q. PLEASE EXPLAIN WHY TGS IS REQUESTING RECOVERY OF HURRICANE HARVEY RESPONSE COSTS IN THIS FILING.

A. In 2017, Hurricane Harvey struck the southern coast of Texas and caused flooding and physical damage to the Company's facilities in its GCSA. The Company undertook restoration efforts after Hurricane Harvey caused damage, particularly flood damage, to facilities in the Company's GCSA. On April 16, 2019, the Company made filings with the municipalities of Galveston, Jamaica Beach, Bayou Vista, Groves, Nederland, Port Arthur and Port Neches, Texas (collectively "GCSA Cities") and the Commission to recover the costs associated with the Company's response to Hurricane Harvey through a proposed rider, Rate Schedule HARV-Rider. The Commission docketed the filing as GUD No. 10844.

Q. PLEASE DESCRIBE THE FINAL RESOLUTION OF GUD NO. 10844.

A. All parties reached a settlement agreement that did not address TGS's recovery of Hurricane Harvey costs at that time. Instead, TGS was authorized to record and defer the $714,389 in Hurricane Harvey restoration costs as a regulatory asset and is required to address the asset in its next full rate case. The Commission approved the settlement agreement in the Final Order for GUD No. 10844.

Q. PLEASE DESCRIBE THE ACTIONS TAKEN BY THE GCSA CITIES RELATED TO THE TGS REQUEST TO RECOVER HURRICANE HARVEY RESTORATION COSTS.

A. The cities of Galveston and Bayou Vista approved the settlement agreement. The Cities of Groves, Nederland, Port Arthur and Port Neches denied the Company's request. The Company appealed the denial, and the Commission consolidated the appeal into GUD No. 10844. These cities then participated in the settlement agreement as a party to GUD No. 10844. The City of Jamaica Beach took no action, and the Company elected to treat customers within Jamaica Beach similarly to those in the other cities. That is, the Company did not implement the proposed rider for those customers.

Q. WHAT STEPS DID TGS TAKE TO PREPARE FOR HURRICANE HARVEY MAKING LANDFALL AND IN THE AFTERMATH OF THE STORM?

A. In May 2017, personnel in the Company's GCSA completed the annual Hurricane Plan review with their teams, and Company personnel began monitoring all potential storm activity. In August 2017, TGS implemented the sequential phases of the Hurricane Plan acting to secure assets, ensure supplies and establish a communication plan, as described in the ONE Gas Emergency Response Plan. Following landfall, Company personnel first assessed and documented the damage, followed by a restoration phase in which approximately 3,100 regulators and 1,100 meters were replaced. In addition, the Company turned off over 600 accounts at the request of customers. All of these efforts were undertaken to ensure the safe and reliable operation of the Company's system.

Q. WHAT TYPES OF COSTS DID TGS INCUR RELATED TO RESTORING SERVICE AFTER THE HURRICANE?

A. The Company incurred costs associated with regular labor, overtime labor, travel-related expenses such as meals and hotels, vehicle expenses and materials and supplies.

Q. WHAT ARE THE COSTS ASSOCIATED WITH THE COMPANY'S HURRICANE RESPONSE EFFORTS?

A. As shown Exhibit SLM-4, expenses associated with the response to Hurricane Harvey total $988,890. The Company is not seeking recovery of any capital costs through the proposed Rate Schedule HARV-Rider.

Q. DID THE COMPANY RECEIVE ANY INSURANCE PROCEEDS RELATED TO THE HURRICANE?

A. Yes. The Company was covered by insurance for this event, but the total costs were less than the Company's $2 million deductible (insurance deductible level in 2017). However, certain travel and overtime costs were covered under a different, time-based deductible in the policy. For these expenses, the Company received insurance reimbursement for expenses incurred after the first twenty-one days, totaling $242,400. In addition, the Company received $61,878 under business interruption coverage to reimburse the Company for some of the lost revenue due to interruption of service. Exhibit SLM-5 (Confidential) contains a copy of the insurance settlement.

Q. ARE THE COSTS THE COMPANY PROPOSES TO RECOVER NET OF ANY INSURANCE PROCEEDS?

A. The expense reimbursement of $242,400 for labor and direct costs has been credited against the costs for which the Company seeks recovery in this filing. The business interruption reimbursement was not credited against the costs for which the Company seeks recovery, because the Company is not seeking recovery from customers of lost revenues.

Q. WERE ANY OTHER ADJUSTMENTS MADE TO THE COSTS THE COMPANY PROPOSES TO RECOVER?

A. Yes. The expenses were reduced by amounts for meals in excess of $25 per person per meal and nightly lodging costs over $150 per night.

Q. WHAT ARE THE TOTAL RESTORATION COSTS, NET OF THE INSURANCE PROCEEDS AND ANY OTHER ADJUSTMENTS, THE COMPANY SEEKS TO RECOVER?

A. As shown on Schedule G-25, the Company requests recovery of $714,389 in total, levelized over six years, which is the maximum number of years between rate cases if the Company makes annual interim rate adjustment filings.

Q. HOW DOES TGS PROPOSE TO RECOVER THE COSTS ASSOCIATED WITH THE HURRICANE RESPONSE?

A. The Company proposes to recover the costs from proposed CGSA customers via a rider with a volumetric surcharge. Exhibit SLM-6 shows the calculation of the surcharge. The total costs to be recovered on line 22 are divided by two years, and the resulting annual recovery is divided by annual volumes for the proposed CGSA to derive a surcharge rate of $0.00182 per Ccf, shown on line 26. If the proposed rider is approved, the costs shown on Schedule G-25 should be removed from the base rate revenue requirement. Alternatively, if the proposed rider is not approved, the Company proposes to recover the costs from proposed CGSA customers via base rates.

Q. PLEASE DESCRIBE PROPOSED RATE SCHEDULE HARV-RIDER.

A. The proposed Rate Schedule HARV-Rider, Hurricane Harvey Surcharge Rider, provides for a surcharge rate of $0.00182 per Ccf to be charged to all gas sales and standard transportation customers in the proposed CGSA until all approved Hurricane Harvey costs and associated rate case expenses have been recovered. The Rate Schedule also provides for an annual reporting mechanism until the full amount is recovered.

Q. DOES TGS PROPOSE TO RECOVER ANY RATE CASE EXPENSES ASSOCIATED WITH THE INITIAL HURRICANE HARVEY FILINGS?

A. Yes. Pursuant to the settlement agreement, TGS seeks to include all rate case expenses incurred in connection with the initial Hurricane Harvey filings, to be reviewed for reasonableness and recovered along with any rate case expenses incurred in connection with this filing. This includes expenses TGS incurred as well as expenses for the Cities of Galveston, Port Neches, Groves, Port Arthur and Nederland.

Q. WHAT OTHER INFORMATION IS TGS PROVIDING IN THIS RATE CASE RELATED TO THE HURRICANE HARVEY COSTS IT SEEKS TO RECOVER?

A. Attached as Exhibit SLM-7, is a copy of the Company's original Statement of Intent filing in which it requested recovery of Hurricane Harvey costs. This includes a cover pleading, my direct testimony and schedules supporting the amounts and calculations for the proposed surcharge. I have also included in my workpapers TGS's responses to discovery in GUD No. 10844, which reflect parties' review of the costs TGS seeks to recover. Parties may continue that review in this case.

VIII. COST RECOVERY RIDERS

A. Pipeline Integrity Testing

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR THE RECOVERY OF PIPELINE INTEGRITY TESTING EXPENSES.

A. In GUD No. 10526, the Commission ordered that pipeline integrity testing expense be recovered via a rider rather than in base rates in the CTSA. To continue the treatment afforded by the Commission in GUD No. 10526, the Company requests implementation of revised Rate Schedules PIT and PIT-Rider, applicable to all gas sales and standard transportation customers in the proposed CGSA, 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 El Paso service area 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."[7] 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

[7] GUD No. 9988, Final Order at Finding of Fact 22 (Dec. 14, 2010).

rates. Finally, a PIT rider has operated successfully and effectively in the CTSA since the last rate case in 2016. Nevertheless, if the proposed Rate Schedule PIT is not approved, pipeline integrity testing expenses should be included in the calculation of base rates, as discussed in the testimony of Ms. Michels.

B. Natural Event Response Rider

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RIDER TO ADDRESS DEFINED NATURAL EVENTS.

A. The Company is proposing a tariff, Rate Schedule NER, that authorizes TGS to defer expenses associated with the response to storms and other natural disasters or events and to later seek recovery of those costs, less any insurance reimbursement, from customers via a surcharge. The framework of the tariff is consistent with recent approvals issued by the city of Galveston and the Commission in GUD No. 10844 for TGS to defer costs and create a regulatory asset for the Company's Hurricane Harvey response costs.

Q. TO WHAT NATURAL EVENTS WOULD RATE SCHEDULE NER APPLY?

A. The provisions of the tariff would apply to expenses TGS incurs responding to a hurricane, tropical storm, tornado, earthquake, ice storm, flood or other wind or water-related events.

Q. WHAT EXPENSES WOULD RATE SCHEDULE NER AUTHORIZE TGS TO DEFER?

A. Under the proposed Rate Schedule NER, TGS would be authorized to defer contractor costs, Company overtime labor, travel, meals, hotels, vehicle expenses, communication expenses, tools, materials and supplies, and any other operating and maintenance expenses reasonably necessary to safely and effectively respond to an event and restore natural gas service. Capital expenditures by the Company, and the regular labor cost of TGS employees would not be deferred for recovery through the proposed rate schedule.

Q. DOES RATE SCHEDULE NER ADDRESS INSURANCE REIMBURSEMENTS RELATED TO NATURAL EVENTS?

A. Yes, Rate Schedule NER states that insurance reimbursements for expenses associated with responding to a natural event must be netted against those expenses. However, insurance reimbursements for capital losses or for lost revenue due to a natural event are not to be netted against expense, because the capital losses and lost revenues would not be recoverable from customers under Rate Schedule NER.

Q. WHY IS IT APPROPRIATE TO DEFER THE EXPENSES ASSOCIATED WITH RESPONDING TO A NATURAL EVENT AND LATER RECOVER THOSE COSTS THROUGH A SURCHARGE?

A. Events of this type occur at irregular and unpredictable intervals and give rise to costs outside of ordinary system operations. Consequently, recovery of the associated expenses via base rates may present timing challenges. Additionally, deferral of the expenses allows time for the related insurance reimbursements to be matched up with the expenses, ensuring recovery of the appropriate amount from customers.

Q. DOES RATE SCHEDULE NER GUARANTEE THE COMPANY RECOVERY OF ANY CLAIMED NATURAL EVENT RESPONSE EXPENSES?

A. No. Rate Schedule NER simply authorizes TGS to defer the costs and to request recovery at a future date, subject to regulatory review and approval. The regulatory authority will determine the reasonableness and necessity of the costs and the appropriate surcharge, if any, when the Company makes the specific request for recovery. If a surcharge is requested and approved for a specific natural event, that surcharge will be reflected on Rate Schedule NER-RIDER[8] and will be charged until the authorized expenses for that event have been recovered.

IX. RATE CASE EXPENSES

Q. IS THE COMPANY REQUESTING RATE CASE EXPENSE RECOVERY IN THIS CASE?

A. Yes. Pursuant to GURA § 104.051 and Commission Substantive 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

[8] Rate Schedule NER sets forth the calculation and requirements for costs related to a natural event, while Rate Schedule NER-Rider contains the rate currently in effect for a specific event.

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 Schedule RCE and Rate Schedule RCE-ENV to enable the Company to recover all rate case expenses determined to be reasonable.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

July 19, 2019

Via Hand Delivery

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

RE: ONE Gas, Inc.'s Texas Utilities Code Section 102.051 Notification

Dear Ms. French,

In accordance with the provisions of Section 102.051 of the Texas Utilities Code, ONE Gas, Inc. provides the following Notification: effective June 30, 2019, ONE Gas, Inc. purchased ONEOK Transmission Company L.L.C. ("ONEOK"), a natural gas pipeline system extending from Kyle, Texas to Cuero, Texas, at a price in excess of $1 million. Under ONE Gas, Inc. ownership, the pipeline system is now ONE Gas Pipeline Company, L.L.C. ("Company"). The Company is an affiliate of Texas Gas Service Company, a division of ONE Gas, Inc. ("TGS"), which is a local distribution company that provides natural gas service throughout the state and is subject to regulation by the Railroad Commission of Texas ("Commission").

Previously, the pipeline was operated by TGS under an operating agreement with ONEOK. TGS will remain the operator of the Company under the P-5 currently on file with the Commission under operator number 845951. Consequently, no workforce changes or reductions were contemplated or experienced as a result of this transaction. To date, the transaction has been seamless with respect to services being provided to customers. The facilities ONE Gas, Inc. acquired that are owned by the Company are used to provide transportation service in TGS's Central Texas Service Area.

ONE Gas, Inc. believes this transaction is in the public interest and will enhance TGS's ability to continue to provide safe, reliable service to its customers. If you have any questions regarding the transaction, please feel free to contact Stacey McTaggart at (512) 370-8354 or Stacey.McTaggart@onegas.com.

Best regards,

David Scalf

David Scalf
Vice President of Rates & Regulatory
ONE Gas, Inc.

cc: Stephanie Houle

RAILROAD COMMISSION OF TEXAS
OVERSIGHT AND SAFETY DIVISION
GAS SERVICES

October 9, 2019

Stacey McTaggart
Rates and Regulatory Director
Texas Gas Service
1301 S. MoPac Expressway, Suite 400
Austin, TX 78746

RE: **Gas Utilities Docket No. 10877:** Application filed by ONE Gas, Inc. to report an acquisition from ONEOK Transmission Company L.L.C.

EXAMINER'S LETTER NO. 4
Receipt of Report of Acquisition of Assets

Dear Ms. McTaggart:

On July 18, 2019, the Railroad Commission of Texas (Commission) received the above referenced report the transaction between ONE Gas, Inc. (ONE Gas) and ONEOK Transmission Company, LLC (ONEOK) providing notice of this acquisition of assets. This letter is to acknowledge receipt of the notice of the acquisition pursuant to Texas Utilities Code § 102.051.

In consideration of the transaction as reported, no additional supporting information will be needed at the present time. However, TEX. UTIL. CODE § 102.051 (b) states "…the railroad commission shall investigate the transaction…to determine whether the action is consistent with the public interest. In reaching its determination, the railroad commission shall consider the reasonable value of the property, facilities, or securities to be acquired, disposed of, merged, or consolidated." In determining reasonable value, the Commission's practice has been to consider original cost. As a general regulatory principle, the term 'original cost,' when used in the context of utility property, is the cost of such property to the person first devoting it to public service.[1]

[1] With limited and specific exceptions, each Texas gas utility shall utilize the Federal Energy Regulatory Commission's Uniform System of Accounts for all operating and reporting purposes. (16 TEX. ADMIN. CODE § 7.310)

1701 NORTH CONGRESS AVENUE ★ POST OFFICE BOX 12967 ★ AUSTIN, TEXAS 78711-2967 ★ PHONE: 512/463-7167 ★ FAX: 512/463-7962
TDD 800/735-2989 OR TDY 512/463-7284 ★ AN EQUAL OPPORTUNITY EMPLOYER ★ HTTP://WWW.RRC.TEXAS.GOV

If the value of the acquired assets becomes the subject of a future cost of service rate proceeding, the Commission's determination as to whether this transaction was in the public interest and the appropriate accounting treatment for the transaction will be determined in such a proceeding based on original cost information. In that circumstance, the Company will be required to provide original cost information for the subject assets in addition to any other supporting information deemed to be material to a public interest review. TEX. UTIL. CODE § 102.051(c) emphasizes "If the railroad commission finds that a transaction is not in the public interest, the railroad commission shall take the effect of the transaction into consideration in ratemaking proceedings and disallow the effect of the transaction if the transaction will unreasonably affect rates or service."

Thank you for your cooperation in this matter. Please contact the undersigned should you have any questions or for further assistance regarding the review of this transaction at Sarah.Montoya-Foglesong@rrc.texas.gov or (512) 475-1958.

Sincerely,

Sarah Montoya-Foglesong

Sarah Montoya-Foglesong
Financial Analyst
Market Oversight Section

Texas Gas Service Company, a Division of ONE Gas, Inc.
CGSA ISOS RTCS TYE June 30, 2019
Updated for Known and Measurable Changes Through September 30, 2019

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2	**OTC/OPC Revenues**												
3													
4													
5		July-18	August-18	September-18	October-18	November-18	December-18	January-19	February-19	March-19	April-19	May-19	June-19
6	Revenues TGS Paid to OTC on behalf of Gas Sales Customers during Test Year	25,924.57	27,387.37	28,850.15	44,508.03	83,497.90	97,611.38	113,444.17	83,365.76	76,126.98	38,903.07	30,816.94	26,222.58
7													
8													**TOTAL**
9	Other Shippers - Prior to June 30, 2019 Acquisition:												**676,658.90**
10		2014	2015	2016	2017	2018		**Annual Average Paid by Others**					
11	Acct. No. 4892103 - Interruptible Transportation Revenue	541,274.65	503,729.13	452,156.19	440,289.98	468,001.99		**481,090.39**					
12													
13													
14		July-19	August-19	September-19	October-19								
15	Revenues TGS Paid to OTC on behalf of Gas Sales Customers - Post Test Year	24,796.83	25,424.25	26,705.39	42,455.29								
16	Revenues Paid to OTC by Other Shippers - Post Test Year	39,977.66	40,439.46	38,074.76	44,267.17								
17		64,774.49	65,863.71	64,780.15	86,722.46								

	A	B	C	D
1				
2	**CALCULATION OF OPC COST OF SERVICE IN PROPOSED RATES**			
3				
4				
5	**Line No.**	**Description**	**Source**	**Amount**
6				
7	1	OPC Gross Plant	WKP C.a	$8,024,125
8	2	OPC Accumulated Depreciation	WKP D.a	(2,973,659)
9	3	OPC Net Plant		$5,050,466
10	4	Pretax Rate of Return	SCH E	9.58%
11	5	Return		$483,835
12	6	Depreciation	WKP G-15.a.1	148,277
13	7	Ad Valorem Tax	SCH G-16	43,434
14	8	O&M expense	WKP G.a.2	283,146
15	9	OPC Cost of Service in Proposed Rates		$958,692

	A	B	C	D	E	F	G	H	I	J	K
1											
2											
3											
4											
5	**Summary of Expenditures**										
6											
7	**Line No.**	**Description**	**AUG-17**	**SEP-17**	**OCT-17**	**NOV-17**	**DEC-17**	**JAN-18**	**FEB-18**	**MAR-18**	**Total**
8											
9	1	Labor		159,391	33,178						192,570
10	2	Overtime		291,070	44,677						335,747
11	3	Supplies and Expenses		2,077	7,853	4		107	2,192	(2,457)	9,775
12	4	Contractor				15,999					15,999
13	5	Tools			102			20			122
14	6	Freight		250	1,163	111	81				1,605
15	7	Communication			2,909						2,909
16	8	Restoration			7,920						7,920
17	9	Travel		1,468	34,447	72,122	10,125	11,787	6,018		135,966
18	10	Utilities		54	102	452		34	82		723
19	11	Meals		147	40,328	3,653	796	2,058	244		47,225
20	12	Employee Expenses - Other		1,879	9,949	299	116	224			12,467
21	13	Auto Loading		25,827	4,401						30,228
22	14	Stores Overhead	12,428	(11,238)	(3,096)			376			(1,530)
23	15	Stores Issues and Returns	44,325	122,499	(44,981)			2,023			123,867
24	16	Direct Materials Purchases	1,869	8,475	30,072	9,936	7,642	461	14,089	-	72,543
25	17	Permits			753						753
26	18	Total	58,622	601,899	169,778	102,576	18,758	17,091	22,624	(2,457)	988,890

Exhibit SLM-5 is Confidential
and will be provided pursuant to the terms of the Protective Agreement.

Texas Gas Service Company, a Division of ONE Gas, Inc.
CGSA ISOS RTCS TYE June 30, 2019
Updated for Known and Measurable Changes Through September 30, 2019

Surcharge Calculation

Line No.	Description	Account	Amount
1	Labor	091.7550.7550.8740100.10.000000	192,570
2	Overtime	091.7550.7550.8740100.16.000000	335,747
3	Supplies and Expenses	091.7550.7550.8740100.21.000000	9,775
4	Contractor	091.7550.7550.8740100.23.000000	15,999
5	Tools	091.7550.7550.8740100.25.000000	122
6	Freight	091.7550.7550.8740100.26.000000	1,605
7	Communication	091.7550.7550.8740100.32.000000	2,909
8	Restoration	091.7550.7550.8740100.34.000000	7,920
9	Travel	091.7550.7550.8740100.35.000000	135,966
10	Utilities	091.7550.7550.8740100.37.000000	723
11	Meals	091.7550.7550.8740100.42.000000	47,225
12	Employee Expenses - Other	091.7550.7550.8740100.44.000000	12,467
13	Auto Loading	091.7550.7550.8740100.45.000000	30,228
14	Stores Overhead	091.7550.7550.8740100.50.000000	(1,530)
15	Stores Issues and Returns	091.7550.7550.8740100.51.000000	123,867
16	Direct Materials Purchases	091.7550.7550.8740100.52.000000	72,543
17	Permits	091.7550.7550.8740100.72.000000	753
18	Subtotal Expenses		988,890
	Less:		
19	Meals & Hotel Over Limit (1)		(32,102)
20	Insurance Settlement		(242,400)
21	Subtotal Deductions		(274,501)
22	Total to Recover		714,389
23	Recovery period (years)		2
24	Annual Recovery		357,194
25	Annual Volumes (Ccf)		195,877,421
26	Surcharge Rate per Ccf		0.00182

(1) Removal of meals over $25 per person per meal and hotels over $150 per night.

Coffin | Renner

April 16, 2019

Via Hand Delivery

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

Re: GUD No. _________; *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Rates to Recover Hurricane Harvey Response Costs Within the Gulf Coast Service Area*

Dear Ms. French:

Enclosed for filing are an original and eleven copies of Texas Gas Service Company, a Division of ONE Gas, Inc.'s ("TGS" or the "Company") Statement of Intent to increase rates within the unincorporated areas of the Gulf Coast Service Area ("GCSA"), including supporting exhibits and a flash drive that contains the electronic files.

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

Best regards,

Kate Norman

Kate Norman
Attorney for Texas Gas Service Company

KWN:ssm
Enclosures

cc: Mark Evarts – Market Oversight Section Director
Stephanie Houle
Stacey McTaggart

GAS UTILITIES DOCKET NO. _______

STATEMENT OF INTENT OF	**§**	
TEXAS GAS SERVICE COMPANY, A	**§**	**BEFORE THE**
DIVISION OF ONE GAS, INC., TO	**§**	
INCREASE RATES TO RECOVER	**§**	**RAILROAD COMMISSION**
HURRICANE HARVEY RESPONSE	**§**	
COSTS WITHIN THE GULF COAST	**§**	**OF TEXAS**
SERVICE AREA	**§**	
	§	

TEXAS GAS SERVICE COMPANY'S STATEMENT OF INTENT TO INCREASE RATES TO RECOVER HURRICANE HARVEY RESPONSE COSTS WITHIN THE GULF COAST SERVICE AREA

Texas Gas Service Company ("TGS" or "the Company"), a division of ONE Gas, Inc. ("ONE Gas") and a "gas utility" under Texas Utilities Code § 101.003(7), respectfully files this Statement of Intent, pursuant to Subchapter C of Chapter 104 of the Texas Utilities Code and the rules of the Gas Services Department of the Railroad Commission of Texas ("Commission"), to recover Hurricane Harvey response costs within the Gulf Coast Service Area ("GCSA"). Contemporaneously with this filing, TGS is filing a Statement of Intent to Increase Rates with the municipalities retaining original jurisdiction in the GCSA.

The Company requests that the proposed rate schedules and tariffs for the GCSA, **Exhibit A** to this Statement of Intent and incorporated herein by reference, become effective on May 21, 2019, which is 35 days from the date of this filing. In support of its request, the Company respectfully shows as follows:

I. INTRODUCTION AND SUMMARY OF THE RATE REQUEST

By this filing, the Company proposes implementation of a Hurricane Harvey Surcharge ("Rate Schedule HARV-RIDER") to recover over a two-year period the Company's costs related to restoration of its system following the impact of Hurricane Harvey. Recovery through a two-year surcharge rather than adjusting base rates for the increase in expenses will lessen the monthly impact on TGS's GCSA customers. Although the Company was covered by insurance for this event, the total costs were less than the Company's $2 million deductible. Certain travel and overtime costs were applied to a different, time-based deductible in the policy. For these expenses, the Company received insurance reimbursement for expenses incurred after the first twenty-one days. That insurance reimbursement of $242,399.50 has been credited against the costs for which the Company seeks recovery in this filing.

The costs for which the Company seeks recovery primarily include travel and labor to assess the damage Hurricane Harvey caused and labor and materials costs to repair or replace thousands of meters and regulators. TGS proposes to collect this amount from all customers in the GCSA, which includes residential, commercial, commercial transportation, industrial, industrial transportation, public authority and public authority transportation customers, as a surcharge on the volumetric rate shown in the attached proposed Rate Schedule HARV-RIDER. In addition, TGS has revised the Cost of Service section of the gas sales rate schedules to reference Rate Schedule HARV-RIDER. The rate schedules and tariffs, attached hereto as **Exhibit A** to the Rate Filing Package and made a part hereof, evidence the rate change proposed by the Company.

If approved by the Commission, the proposed surcharge of $0.01406 per Ccf will increase TGS's revenues in the GSCA by $714,389. The Company seeks to recover this amount over a two-year period, which is an annual increase of $357,194 or 1.22% annually including gas costs, or 1.98% annually excluding gas costs. Because the proposed changes will not increase TGS's total aggregate revenues on an annual basis within the GCSA by more than 2.5%, the proposed rate increase does not constitute a "major change" in rates as that term is defined by Texas Utilities Code § 104.101. If the surcharge is approved, the residential and commercial rates within the original jurisdiction of the Commission will not exceed 115% of the average of all rates for similar services of all municipalities served by the same utility within the same county.

Finally, as provided by law, TGS is requesting that the Commission approve the recovery of the reasonable rate case expenses associated with this filing through an addition to the approved surcharge amount. The exact amount will not be known until the case is complete.

II. JURISDICTION

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

III. DETAILS OF PROPOSED CHANGES

A. Rate Filing Package

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

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

B. Effective Date

The Company requests that the Commission order the proposed rates to be effective for bills rendered on and after May 21, 2019.

C. Class and Number of Customers Affected

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

	# of Customers
GCSA Customer Classes	
Residential	1,151
Commercial	29
Commercial Transportation	0
Industrial	0
Industrial Transportation	0
Public Authority	4
Public Authority Transportation	0

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

D. Witness Testimony

Attached as **Exhibit D** to the Statement of Intent is the direct testimony of Stacey McTaggart supporting the Company's requested recovery of costs it incurred to perform restoration efforts following Hurricane Harvey.

IV. RATE CASE EXPENSES

Pursuant to Texas Utilities Code § 104.051 and Commission Substantive Rule 7.5530, TGS requests recovery of all reasonable and necessary Company and any applicable City rate case expenses from affected customers through an addition to the final approved surcharge.

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

The Company will promptly undertake to notify the public of the proposed changes in its gas rates consistent with the requirements of Texas Utilities Code § 104.103 and Commission Substantive Rules §§ 7.230 and 7.235. The public notice that TGS proposes to provide regarding the proposed increase in rates for the GCSA environs is attached as **Exhibit E** to the Statement of

Intent. TGS asks that the Commission approve its form of notice prior to publication, and the Company will submit proof of notice to the Commission promptly upon completion thereof.

VI. COMPANY REPRESENTATIVES FOR NOTIFICATION

TGS's authorized representatives are:

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

and

Kate Norman
C. Glenn Adkins
Coffin Renner LLP
1011 West 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.

VII. REQUEST FOR APPROVAL OF PROTECTIVE ORDER

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

VIII. CONCLUSION

TGS requests that the Commission: (1) establish rates for the GCSA consistent with the proposed Rate Schedule HARV-RIDER to become effective for bills rendered on and after May 21, 2019; (2) authorize the Company to recover all reasonable rate case expenses incurred in connection with this Statement of Intent filing; and (3) for such further relief to which the Company may be entitled.

Respectfully submitted,

By: Kate Norman

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ATTORNEYS FOR TEXAS GAS SERVICE COMPANY

HURRICANE HARVEY SURCHARGE

A. APPLICABILITY

The Hurricane Harvey Surcharge rate as set forth in Section (B) below is for the recovery of losses incurred by the Company as a direct result of Hurricane Harvey and not recoverable from any other source. The 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 Gulf Coast service area within the incorporated and unincorporated areas of Bayou Vista, Galveston, Groves, Jamaica Beach, Nederland, Port Arthur, and Port Neches, Texas: 10, 20, 30, 40, 1Z, 2Z, 3Z, 4Z, T-1, and T-1-ENV.

B. SURCHARGE RATE

All Ccf during each billing period: $0.01406 per Ccf

This rate will be in effect until all approved and expended Hurricane Harvey costs and associated rate case expenses are recovered under the applicable rate schedules.

C. OTHER ADJUSTMENTS

Taxes: Plus applicable taxes and fees related to above.

D. CONDITIONS

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

E. COMPLIANCE

TGS shall file a reconciliation report annually on or before December 31st, commencing in 2019. TGS shall file the report with the Commission, addressed to the Director of the Oversight and Safety Division and referencing Gas Utilities Docket No. _____, Hurricane Harvey 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

RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a residential customer 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. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

Incorporated areas served in Galveston, Bayou Vista, Jamaica Beach, Port Arthur, Nederland, Groves and Port Neches, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$12.10 plus
All Ccf per monthly billing period @	$0.45616 per Ccf

OTHER ADJUSTMENTS

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

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

Rate Schedule RCE: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider.

Rate Schedule HARV-RIDER: Adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider.

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

CONDITIONS

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

COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to commercial consumers for all purposes and all other consumers not otherwise specifically provided for.

TERRITORY

Incorporated areas served in Galveston, Bayou Vista, Jamaica Beach, Port Arthur, Nederland, Groves and Port Neches, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$49.49 plus
All Ccf per monthly billing period @	
The First 250 Ccf @	$0.22140 per Ccf
All Over 250 Ccf @	$0.19380 per Ccf

OTHER ADJUSTMENTS

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

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

Rate Schedule RCE: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider.

Rate Schedule HARV-RIDER: Adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider.

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

CONDITIONS

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

The rate schedule may be used for special unmetered service such as gas street lights. The total hourly rated consumption of all gas burning appliances included, expressed in Ccf, at the location, shall be multiplied by 731 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.

INDUSTRIAL SERVICE RATE

APPLICABILITY

Applicable to any qualifying 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

Incorporated areas served in Galveston, Bayou Vista, Jamaica Beach, Port Arthur, Nederland, Groves and Port Neches, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$153.41 plus
All Ccf per monthly billing period @	
The First 250 Ccf @	$0.40060 per Ccf
All Over 250 Ccf @	$0.37480 per Ccf

OTHER ADJUSTMENTS

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

Rate Schedule RCE: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider.

Rate Schedule HARV-RIDER: Adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider.

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

CONDITIONS

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

Delivery of gas hereunder may be interrupted or curtailed at the discretion of Texas Gas Service Company, a Division of ONE Gas, Inc., in case of shortage or threatened shortage of gas supply from any cause whatsoever, to conserve gas for residential and other customers served.

PUBLIC AUTHORITY SERVICE RATE

APPLICABILITY

Applicable to all public and parochial schools and colleges, and to all facilities operated by Governmental agencies not specifically provided for in other rate schedules or special contracts. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

Incorporated areas served in Galveston, Bayou Vista, Jamaica Beach, Port Arthur, Nederland, Groves and Port Neches, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$103.95 plus
All Ccf per monthly billing period @	
The First 250 Ccf @	$0.15672 per Ccf
All Over 250 Ccf @	$0.13092 per Ccf

OTHER ADJUSTMENTS

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

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

Rate Schedule RCE: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider.

Rate Schedule HARV-RIDER: Adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider.

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

CONDITIONS

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

The rate schedule may be used for special unmetered service such as gas street lights. The total hourly rated consumption of all gas burning appliances included, expressed in Ccf, at the location, shall be multiplied by 731 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.

RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a residential customer 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. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

Unincorporated areas served in the vicinity of Galveston, Bayou Vista, Jamaica Beach, Port Arthur, Port Neches, Nederland, and Groves, Texas.

COST OF SERVICE RATE:

During each monthly billing period:

A customer charge per meter per month of	$13.00 plus
Interim Rate Adjustment (IRA)	$ 1.00 per month (Footnote 1)
Total Customer Charge	$14.00 per month
All Ccf per monthly billing period @	$0.40680 per Ccf (Footnote 2)

OTHER ADJUSTMENTS

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

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

Rate Schedule RCE: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider.

Rate Schedule HARV-RIDER: Adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider.

Taxes: Plus applicable taxes and fees related to above.

CONDITIONS

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

Footnote 1: 2016 IRA - $0.71 (GUD No. 10666); 2017 IRA - $0.29 (GUD No. 10781)
Footnote 2: $0.45646 (GUD No. 10488) revised to $0.40680 (GUD No. 10730)

COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to commercial consumers for all purposes and all other consumers not otherwise specifically provided for.

TERRITORY

Unincorporated areas served in the vicinity of Galveston, Bayou Vista, Jamaica Beach, Port Arthur, Port Neches, Nederland and Groves, Texas.

COST OF SERVICE RATES

During each monthly billing period:

A customer charge per meter per month of	$54.00 plus
Interim Rate Adjustment (IRA)	$ 5.05 per month (Footnote 1)
Total Customer Charge	$59.05 per month
All Ccf per monthly billing period @	
The First 250 Ccf @	$0.20185 per Ccf (Footnote 2)
All Over 250 Ccf @	$0.17425 per Ccf (Footnote 3)

OTHER ADJUSTMENTS

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

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

Rate Schedule RCE: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider.

Rate Schedule HARV-RIDER: Adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider.

Taxes: Plus applicable taxes and fees related to above.

CONDITIONS

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

2. The rate schedule may be used for special unmetered service such as gas street lights. The total hourly rated consumption of all gas burning appliances included, expressed in Ccf, at the location, shall be multiplied by 731 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.

Footnote 1: 2016 IRA - $3.57 (GUD No. 10666); 2017 IRA - $1.48 (GUD No. 10781)
Footnote 2: $0.22140 (GUD No. 10488) revised to $0.20185 (GUD No. 10730)
Footnote 3: $0.19380 (GUD No. 10488) revised to $0.17425 (GUD No. 10730)

INDUSTRIAL SERVICE RATE

APPLICABILITY

Applicable to any qualifying 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

Unincorporated areas served in the vicinity of Galveston, Bayou Vista, Jamaica Beach, Port Arthur, Port Neches, Nederland and Groves, Texas.

COST OF SERVICE RATES

During each monthly billing period:

A customer charge per meter per month of	$110.00 plus
Interim Rate Adjustment (IRA)	$115.52 per month (Footnote 1)
Total Customer Charge	$225.52 per month
All Ccf per monthly billing period @	
The First 250 Ccf @	$0.37808 per Ccf (Footnote 2)
All Over 250 Ccf @	$0.35228 per Ccf (Footnote 3)

OTHER ADJUSTMENTS

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

Rate Schedule RCE: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider.

Rate Schedule HARV-RIDER: Adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider.

Taxes: Plus applicable taxes and fees related to above.

CONDITIONS

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

2. Delivery of 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 customers served.

Footnote 1: 2016 IRA - $85.98 (GUD No. 10666); 2017 IRA - $29.54 (GUD No. 10781)
Footnote 2: $0.40060 (GUD No. 10488) revised to $0.37808 (GUD No. 10730)
Footnote 3: $0.37480 (GUD No. 10488) revised to $0.35228 (GUD No. 10730)

PUBLIC AUTHORITY SERVICE RATE

APPLICABILITY

Applicable to all public and parochial schools and colleges, and to all facilities operated by Governmental agencies not specifically provided for in other rate schedules or special contracts. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

Unincorporated areas served in the vicinity of Galveston, Bayou Vista, Jamaica Beach, Port Arthur, Port Neches, Nederland and Groves, Texas.

COST OF SERVICE RATES

During each monthly billing period:

A customer charge per meter per month of	$110.00 plus
Interim Rate Adjustment (IRA)	$ 6.63 per month (Footnote 1)
Total Customer Charge	$116.63 per month

All Ccf per monthly billing period @

The First 250 Ccf @	$0.13587 per Ccf (Footnote 2)
All Over 250 Ccf @	$0.11007 per Ccf (Footnote 3)

OTHER ADJUSTMENTS

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

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

Rate Schedule RCE: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider.

Rate Schedule HARV-RIDER: Adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider.

Taxes: Plus applicable taxes and fees related to above.

CONDITIONS

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

2. The rate schedule may be used for special unmetered service such as gas street lights. The total hourly rated consumption of all gas burning appliances included, expressed in Ccf, at the location, shall be multiplied by 731 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.

Footnote 1: 2016 IRA - $4.66 (GUD No. 10666); 2017 IRA - $1.97 (GUD No. 10781)
Footnote 2: $0.15672 (GUD No. 10488) revised to $0.13587 (GUD No. 10730)
Footnote 3: $0.13092 (GUD No. 10488) revised to $0.11007 (GUD No. 10730)

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 the Company's 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 Gulf Coast Service Area distribution system which includes the environs of Galveston, Bayou Vista, Jamaica Beach, Port Arthur, Port Neches, Groves and Nederland, 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	$ 300.00 per month			
plus Interim Rate Adjustments		$5.05 (Footnote 1)	Total Rate	$305.05
Industrial	$ 300.00 per month			
plus Interim Rate Adjustments		$115.52 (Footnote 2)	Total Rate	$415.52
Public Authority	$ 300.00 per month			
plus Interim Rate Adjustments		$6.63 (Footnote 3)	Total Rate	$306.63

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

Commercial	The First 250 Ccf@	$ 0.20185 per Ccf (Footnote 4)
	All Over 250 Ccf @	$ 0.17425 per Ccf (Footnote 5)
Industrial	The First 250 Ccf@	$ 0.37808 per Ccf (Footnote 6)
	All Over 250 Ccf @	$ 0.35228 per Ccf (Footnote 7)
Public Authority	The First 250 Ccf@	$ 0.13587 per Ccf (Footnote 8)
	All Over 250 Ccf @	$ 0.11007 per Ccf (Footnote 9)

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

3) Rate Schedule RCE: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider.

4) Rate Schedule HARV-RIDER: Adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider.

Subject To

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

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

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

Footnote 1: 2016 IRA - $3.57 (GUD No. 10666); 2017 IRA - $1.48 (GUD No. 10781)
Footnote 2: 2016 IRA - $85.98 (GUD No. 10666); 2017 IRA - $29.54 (GUD No. 10781)
Footnote 3: 2016 IRA - $4.66 (GUD No. 10666); 2017 IRA - $1.97 (GUD No. 10781)
Footnote 4: $0.22140 (GUD No. 10488) revised to $0.20185 (GUD No. 10730)
Footnote 5: $0.19380 (GUD No. 10488) revised to $0.17425 (GUD No. 10730)
Footnote 6: $0.40060 (GUD No. 10488) revised to $0.37808 (GUD No. 10730)
Footnote 7: $0.37480 (GUD No. 10488) revised to $0.35228 (GUD No. 10730)
Footnote 8: $0.15672 (GUD No. 10488) revised to $0.13587 (GUD No. 10730)
Footnote 9: $0.13092 (GUD No. 10488) revised to $0.11007 (GUD No. 10730)

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's distribution system. The customer must arrange with its gas supplier to have the customer's gas delivered to one of Texas Gas Service's existing delivery receipt points for transportation by Texas Gas Service to the customer's facilities at the customer's delivery point. The receipt points shall be specified by Texas Gas Service 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 Texas Gas Service's Gulf Coast Service Area distribution system which includes the incorporated areas of Galveston, Bayou Vista, Jamaica Beach, Port Arthur, Port Neches, Groves and Nederland, Texas. Such service shall be provided at any point on Texas Gas Service'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 Texas Gas Service 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	$295.49	per month
Industrial	$217.42	per month
Public Authority	$302.36	per month

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

Commercial	The First 250 Ccf@	$0.22140 per Ccf
	All Over 250 Ccf @	$0.19380 per Ccf
Industrial	The First 250 Ccf@	$0.40060 per Ccf
	All Over 250 Ccf @	$0.37480 per Ccf
Public Authority	The First 250 Ccf@	$0.15672 per Ccf
	All Over 250 Ccf @	$0.13092 per Ccf

Additional Charges:

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

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

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

4) Rate Schedule RCE: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider.

5) Rate Schedule HARV-RIDER: Adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider.

Subject To

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

2) Transportation of natural gas hereunder may be interrupted or curtailed at the discretion of Texas Gas Service 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 Texas Gas Service's rate schedule which would otherwise be available to such customer.

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

Texas Gas Service, a Division of ONE Gas, Inc
Gulf Coast Service Area
Hurricane Harvey Surcharge

Exhibit B

Annual Revenue Increase by Class

Line No.	Description	Residential Incorporated	Commercial Incorporated	Industrial Incorporated	Public Authority Incorporated	Commercial Standard Transport Incorporated	Public Authority Transport Incorporated	Industrial Standard Transport Incorporated	Total Incorporated
1	Incorporated Annual Revenue Increase	$198,348	$79,419	$0	$22,520	$38,389	$0	$12,260	$350,936
2	Incorporated Customer Count	41,353	1,767	-	267	29	-	4	43,420
		Residential Environs	**Commercial Environs**	**Industrial Environs**	**Public Authority Environs**	**Commercial Standard Transport Environs**	**Public Authority Transport Environs**	**Industrial Standard Transport Environs**	**Total Environs**
3	Environs Annual Revenue Increase	$5,737	$491	$0	$31	$0	$0	$0	$6,258
4	Environs Customer Count	1,151	29	-	4	-	-	-	1,184
		Total Residential	**Total Commercial**	**Total Industrial**	**Total Public Authority**	**Total Commercial Standard Transport**	**Total Public Authority Transport**	**Total Industrial Standard Transport**	**Total**
5	Total Annual Revenue Increase	$204,085	$79,910	$0	$22,551	$38,389	$0	$12,260	$357,194
6	Total Customer Count	42,504	1,796	-	271	29	-	4	44,604

Line No.	Description	Percent Increase Without Cost Of Gas Total	Percent Increase With Cost Of Gas Total
7	Annual Increase	$357,194	$357,194
8	Revenues without and with Cost of Gas	18,043,229	29,314,182
9	Percent Increase	1.98%	1.22%

Texas Gas Service, a Division of ONE Gas, Inc.
Gulf Coast Service Area
Hurricane Harvey Surcharge

Environs Customer Bill Impact

Line No.	Customer Class ENVIRONS	Average Usage (Ccf)	Current Monthly Bills	Hurricane Harvey Surcharge	Monthly Bill $ Change	Monthly % Change
1	**RESIDENTIAL**					
2	Cost of Service Only	30	$26.02	$0.42	$0.42	1.60%
3	Total Bill (Note 1)	30	$41.29	$0.42	$0.42	1.01%
4	**COMMERCIAL**					
5	Cost of Service Only	101	$79.42	$1.42	$1.42	1.79%
6	Total Bill (Note 1)	101	$131.58	$1.42	$1.42	1.08%
7	**COMMERCIAL STANDARD TRANSPORT**					
8	Cost of Service Only	0	$305.05	$0.00	$0.00	0.00%
9	Total Bill (Note 1)	0	$305.05	$0.00	$0.00	0.00%
10	**PUBLIC AUTHORITY**					
11	Cost of Service Only	45	$122.78	$0.64	$0.64	0.52%
12	Total Bill (Note 1)	45	$146.20	$0.64	$0.64	0.44%
13	**PUBLIC AUTHORITY STANDARD TRANSPORT (Note 2)**					
14	Cost of Service Only	0	$306.63	$0.00	$0.00	0.00%
15	Total Bill (Note 1)	0	$306.63	$0.00	$0.00	0.00%
16	**INDUSTRIAL (Note 2)**					
17	Cost of Service Only	0	$225.52	$0.00	$0.00	0.00%
18	Total Bill (Note 1)	0	$225.52	$0.00	$0.00	0.00%
19	**INDUSTRIAL STANDARD TRANSPORT**					
20	Cost of Service Only	0	$415.52	$0.00	$0.00	0.00%
21	Total Bill (Note 1)	0	$415.52	$0.00	$0.00	0.00%

Note 1: Total Bills for gas sales customers include 12 month average COG of $0.5170/Ccf and excludes revenue related taxes. Transportation customers secure their own gas, so there is no added COG in the Total Bill.

Note 2: TGS currently has no Industrial gas sales customers or Standard Transport customers, and TGS therefore did not reflect a change to the surcharge.

	$/CCF	
Cost of Gas (Avg)	$	0.5170

GAS UTILITIES DOCKET NO. __________

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO INCREASE RATES TO RECOVER HURRICANE HARVEY RESPONSE COSTS WITHIN THE GULF COAST SERVICE AREA	**§ § § § § §**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

STACEY L. MCTAGGART

ON BEHALF OF

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

April 16, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF STACEY L. MCTAGGART

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stacey L. McTaggart, and my business address is 1301 South MoPac Expressway, Suite 400, Austin, Texas 78746.

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

A. I am the Rates and Regulatory Director for Texas Gas Service Company ("TGS" or the "Company"), 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 in January

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

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

A. Yes, it was.

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

A. Yes. I have prepared and sponsor the exhibits 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. In 2017, Hurricane Harvey struck the southern coast of Texas and caused flooding and physical damage to the Company's facilities in its Gulf Coast Service Area ("GCSA"). The purpose of my testimony is to describe the Company's restoration efforts after Hurricane Harvey caused damage, particularly flood damage, to facilities in the Company's GCSA. Specifically, I describe the Company's:

1. emergency preparedness and response plan;
2. response to Hurricane Harvey to maintain the safety and reliability of its system; and
3. proposed recovery of Hurricane Harvey-related expenses via a proposed rider, Rate Schedule HARV-Rider.

Q. ARE YOU SPONSORING ANY RATE SCHEDULES?

A. Yes, I am sponsoring proposed Rate Schedule HARV-Rider.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have filed testimony on behalf of TGS in numerous proceedings, including GUD Nos. 9770, 9790, 9839, 9988, 10094, 10453, 10488, 10506, 10526, 10656, 10739 and 10766.

II. <u>TGS EMERGENCY RESPONSE PLANS</u>

Q. PLEASE DESCRIBE TGS'S EMERGENCY RESPONSE PLANS.

A. ONE Gas maintains an Emergency Response Plan (Exhibit SLM-1 Confidential), which provides guidance for all ONE Gas operating divisions, including TGS, for a variety of emergency situations including planning objectives, response objectives, response mobilization and demobilization, and communication and documentation requirements. In 2017, TGS maintained a separate Gulf Coast Hurricane Plan ("Hurricane Plan") that set forth annual hurricane preparedness activities as well as the Company's response plan for a hurricane event. That plan is now included as a section in the Emergency Response Plan contained in Exhibit SLM-1. At the beginning of each hurricane season, local management reviews the Hurricane Plan and completes a thorough checklist of equipment and supplies to ensure readiness well before any event is imminent.

Q. PLEASE DESCRIBE TGS'S HURRICANE PREPAREDNESS ACTIVITIES IN 2017.

A. In May 2017, personnel in the Company's GCSA completed the annual Hurricane Plan review with their teams, and Company personnel began monitoring all potential storm activity. On August 22, the Company began to monitor the path and development of then Tropical Storm Harvey. The storm moved across the Yucatan Peninsula and reports indicated it would move into the Gulf of Mexico and strengthen, with landfall predicted within a week. At that time, TGS implemented Phase I of the Hurricane Plan for tropical storms or hurricanes moving in the direction of a Company service area.

III. <u>TGS RESPONSE TO HURRICANE HARVEY</u>

Q. PLEASE DESCRIBE TGS'S PHASE I RESPONSE TO HURRICANE HARVEY.

A. Phase I response activities included:

- Establishing an evacuation timeline;
- Making lodging arrangements in locations where the storm was predicted to make landfall;
- Contacting local government emergency personnel for evacuation plans and timelines;
- Monitoring news reports and information for wind and tidal surge predictions;
- Reviewing the hurricane preparedness checklist and assigning tasks to appropriate personnel;

- Selecting appropriate staging areas for personnel and vehicles to optimize response time;
- Preparing a list of all employees who would act as emergency responders;
- Assigning vehicles to personnel and documenting locations;
- Instructing personnel to keep all vehicles fueled;
- Placing all essential pipeline records and other documents in a fire- and water-proof container;
- Securing valve isolation books and providing multiple electronic and hard copies to appropriate personnel;
- Ensuring that bulk gasoline, diesel, oil and other fuels were at adequate emergency levels;
- Noting the location of portable lighting equipment;
- Keeping batteries charged for all leak detection and communication equipment;
- Ensuring the availability of wireless internet cards; and
- Reviewing the storm predictions and assigned tasks at area staff meetings.

Q. PLEASE DESCRIBE ADDITIONAL STEPS TAKEN BY TGS PERSONNEL AS HURRICANE HARVEY APPROACHED.

A. On August 23 and August 24, TGS personnel completed additional hurricane preparedness steps including:

- Securing information technology ("IT") equipment and local Engineering records;
- Boarding up buildings;
- Moving large equipment to sites beyond the flood zone;

- Checking and adjusting system pressures;
- Checking food and water supplies, and filling all available water containers;
- Assigning responsibilities to the first responders;
- Assigning radios and/or phones to emergency personnel and first responders;
- Confirming vehicle assignments and locations;
- Evacuating non-essential employees; and
- Verifying remaining employees understood work assignments and reporting requirements.

As landfall became imminent, TGS personnel shut down and unplugged all possible equipment; relocated to assigned staging/evacuation areas; established communications with local and state leadership; and resumed monitoring weather and evacuation reports. Hurricane Harvey made landfall on August 25 as a Category 4 hurricane.

Q. FOLLOWING LANDFALL, HOW DID TGS PERSONNEL RESPOND?

A. In the hours after landfall, some emergencies occurred due to trees and other objects falling and damaging meters. The Company was able to respond to these situations and maintain the safety and integrity of the system. Subsequently, the storm stalled for several days, dropping record-breaking rainfall. On August 30, unprecedented additional rainfall totaling approximately 27 inches created wide-spread flooding, including that of the Company's Port Arthur service center and service yard. Many TGS employees were stranded in their homes or at their designated command posts or evacuation points for several days. In all, twenty-one TGS employees sustained some level of water damage to their homes or vehicles and a few had to be rescued by boat. During this time, the Company's ability to respond was limited by the wide-spread flooding of streets and homes, but the situation gradually improved as personnel gained access to the previously flooded areas.

Q. PLEASE DESCRIBE TGS'S RESPONSE FOLLOWING THE FLOODING.

A. TGS began a process to efficiently assess each of the approximately 30,000 active meter settings and to document the associated findings. Documentation and materials were gathered even while the water was still receding, allowing local personnel to begin assessment immediately, while others across the state were staged and ready to respond as soon as roads cleared. In addition to the local employees, almost 100 other employees from across ONE Gas provided "on the ground" assistance for the storm response effort.

Five supervisors from the Gulf Coast and North Texas Service Areas each led a team on the ground, all of whom reported to the TGS Director of Operations, Tony Van Schuyver. Every active meter and regulator were initially assessed on a first pass, and any immediate emergency situation was taken care of on this initial assessment. In non-emergency situations, meters were marked with white paint and their condition was documented. Meters or regulators needing replacement due to being under water or other issues were painted with a white "X;" a white "dot" was painted on meters that did not need further action. Documentation was completed and provided to the command post at the end of each day. The meter assessment activities took a total of approximately fourteen days to complete.

Logistics were also a vital and full-time job. Keeping people fed; distributing water and Gatorade; providing dry socks and clean clothes; ensuring adequate lodging, among other things, were key to supporting the ONE Gas and TGS personnel on the ground who were performing necessary tasks to ensure safety and to identify facilities that needed to be repaired. Teamwork and collaboration were critical components to the successful response.

Daily meetings were held for the first few weeks with the local operations and the support teams in other locations to ensure all needs were met. Safety was stressed at these daily briefings and throughout the event, especially due to hazards in the field that would not normally be encountered – even alligators! The team implemented temporary vehicle safety protocols due to the increased traffic at the service center. Everyone involved was and is very proud that there were zero injuries or accidents during the entire operation.

TGS's Vice-President of Operations, Jim Jarrett, led calls at least daily with the field leadership and offsite functional teams to review status, assess needs, and make tactical decisions. Mr. Jarrett also led recurring meetings with senior management who were actively engaged and providing guidance and direction throughout the event. The Commission and Texas Energy Reliability Council were kept informed throughout the event with thorough, consistent, and timely communication.

Q. PLEASE DESCRIBE THE FINAL OUTCOME OF THE TGS HURRICANE RESPONSE EFFORTS.

A. The TGS team completed the assessment phase in about 2 weeks. The restoration phase began with a pilot team on September 10, ramped up considerably with the personnel coming off the assessment phase, and wrapped up by September 30.

During the restoration phase, the team replaced each of the regulators that had been under water. They changed the meter if it was compromised in any way or if the index was damaged. In all, approximately 3,100 regulators and 1,100 meters were replaced. In addition, the Company turned off over 600 accounts at the request of customers. All of these efforts were undertaken to ensure the safe and reliable operation of the Company's system.

IV. PROPOSED RECOVERY OF HURRICANE HARVEY EXPENSES

Q. WHAT ARE THE COSTS ASSOCIATED WITH THE COMPANY'S HURRICANE RESPONSE EFFORTS?

A. As shown in SOI Exhibit G, Schedule 2, expenses associated with the response to Hurricane Harvey total $988,890. These costs include labor, travel-related expenses, vehicle expenses and materials and supplies. The Company is not seeking recovery of any capital costs through this filing.

Q. DID THE COMPANY RECEIVE ANY INSURANCE PROCEEDS RELATED TO THE HURRICANE?

A. Yes. The Company was covered by insurance for this event, but the total costs were less than the Company's $2 million deductible. However, certain travel and overtime costs fell under a different, time-based deductible in the policy. For these expenses, the Company received insurance reimbursement for expenses incurred after the first twenty-one days. In addition, the Company received $61,878 under business interruption coverage to reimburse the Company for some of the lost revenue due to interruption of service. Exhibit SLM-2 (Confidential) contains a copy of the insurance settlement.

Q. ARE THE COSTS THE COMPANY PROPOSES TO RECOVER NET OF ANY INSURANCE PROCEEDS?

A. The expense reimbursement of $242,399.50 for labor and direct costs has been credited against the costs for which the Company seeks recovery in this filing. The business interruption reimbursement was not credited against the costs for which the Company seeks recovery, because the Company is not seeking recovery from customers of lost revenues.

Q. WERE ANY OTHER ADJUSTMENTS MADE TO THE COSTS THE COMPANY PROPOSES TO RECOVER?

A. Yes. The expenses were reduced by amounts for meals in excess of $25 per person per meal and nightly lodging costs over $150 per night in compliance with typical Commission practice.

Q. WHAT ARE THE TOTAL RESTORATION COSTS, NET OF THE INSURANCE PROCEEDS AND ANY OTHER ADJUSTMENTS, THE COMPANY SEEKS TO RECOVER?

A. As shown on Exhibit G, Schedule 1, the Company requests recovery of $714,389 in total over a two-year period. That amounts to $357,194 per year for the two-year period.

Q. HOW DOES TGS PROPOSE TO RECOVER THE COSTS ASSOCIATED WITH THE HURRICANE RESPONSE?

A. The Company proposes to recover the costs from GCSA customers over a two-year period via a volumetric surcharge. Schedule 1 of SOI Exhibit G shows the calculation of the two-year surcharge. The total costs to be recovered on line 22 are divided by two and further divided by annual volumes for the GCSA to derive a surcharge rate of $0.01406 per Ccf, shown on line 26.

Q. PLEASE DESCRIBE PROPOSED RATE SCHEDULE HARV-RIDER.

A. The proposed Rate Schedule HARV-Rider, Hurricane Harvey Surcharge Rider, is shown in SOI Exhibit A. Rate Schedule HARV-Rider provides for a surcharge rate of $0.01406 per Ccf to be charged to all gas sales and standard transportation customers in the GCSA until all approved Hurricane Harvey costs and associated rate case expenses have been recovered. The Rate Schedule also provides for an annual reporting mechanism until the full amount is recovered.

Q. HOW DOES TGS PROPOSE TO RECOVER ANY RATE CASE EXPENSES ASSOCIATED WITH THIS FILING?

A. To the extent that rate case expenses are incurred by any parties to this filing, the Company proposes to add the approved amount of rate case expenses to the total Hurricane Harvey costs to be recovered under Rate Schedule HARV-Rider.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Exhibits SLM-1 and SLM-2 are CONFIDENTIAL and will be provided pursuant to the terms of the Protective Order.

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 Director – Rates and Regulatory Affairs 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.

Stacey L. McTaggart

SUBSCRIBED AND SWORN TO BEFORE ME by the said Stacey L. McTaggart on this 11th day of April 2019.

Christine Bell
Notary Public in and for the State of Texas

CHRISTINE BELL
NOTARY PUBLIC - STATE OF TEXAS
ID# 130547096
COMM. EXP. 02-19-2020

PUBLIC NOTICE OF PROPOSED RATE INCREASE
NATURAL GAS UTILITY RATES

On April 10, 2019, Texas Gas Service Company ("TGS" or the "Company"), filed a Statement of Intent to Increase Rates ("Statement of Intent") with the Railroad Commission of Texas and with the cities of Bayou Vista, Galveston, Groves, Jamaica Beach, Nederland, Port Arthur, and Port Neches, Texas, for the gas utility rates charged by the Company to customers within the Gulf Coast Service Area ("GCSA"). The proposed increase in rates will affect all customers within the incorporated municipalities and unincorporated areas of the GCSA. The proposed effective date of the requested rate changes is May 21, 2019.

The proposed rates and tariffs are expected to increase the Company's annual revenues for the GCSA by approximately $714,389 in total. The Company seeks to recover this amount over a two-year period, which is an annual increase of $357,194 or 1.22% annually including gas costs, or 1.98% annually excluding gas costs. The proposed change in rates does not constitute a "major change" as that term is defined by Section 104.101 of the Texas Utilities Code because the proposed changes will not increase the total aggregate revenues of the Company by more than two and one-half percent. The proposed change in rates will not become effective until similar changes have become effective within the nearest incorporated city within the GCSA.

There is no current storm surcharge in effect. The Company proposes to implement the surcharge included in Table 1 below:

TABLE 1 - Proposed Rate Changes for all Incorporated and Unincorporated Customers

Customer Class	Number of Customers Affected	Proposed Volumetric Surcharge (per Ccf)
Residential (Env)	1,151	0.01406
Residential (Inc)	41,353	0.01406
Commercial (Env)	29	0.01406
Commercial (Inc)	1,767	0.01406
Commercial Transportation (Env)	0	0.01406
Commercial Transportation (Inc)	29	0.01406
Industrial (Env)	0	0.01406
Industrial (Inc)	0	0.01406
Industrial Transportation (Env)	0	0.01406
Industrial Transportation (Inc)	4	0.01406
Public Authority (Env)	4	0.01406
Public Authority (Inc)	267	0.01406
Public Authority (Env)	0	0.01406
Public Authority Transportation (Inc)	0	0.01406

TGS does not propose any changes to the base volumetric rates or the customer charge or for any customer class.

TABLE 2 - Impact on Average Bill

Customer Class (Average Monthly Usage Mcf or Ccf)	Current Average Monthly Bill with Gas Cost	Proposed Average Monthly Bill with Gas Cost	Proposed Monthly Increase	Percentage Increase with Gas Cost	Percentage Change without Gas Cost
Residential (Inc) (28 Ccf)	$39.76	$40.16	$0.40	1.01%	1.59%
Residential (Env) (30 Ccf)	$41.29	$41.70	$0.42	1.01%	1.60%
Commercial (Inc) (266 Ccf)	$245.69	$249.44	$3.74	1.52%	3.47%
Commercial (Env) (101 Ccf)	$131.58	$133.00	$1.42	1.08%	1.79%
Commercial Transportation (Inc) * (7,756 Ccf)	$5,815.39	$5,924.45	$109.06	1.88%	6.04%
Commercial Transportation (Env) ** (N/A)	$305.05	$305.05	$0.00	0.00%	0.00%
Industrial (Inc)** (N/A)	$153.41	$153.41	$0.00	0.00%	0.00%
Industrial (Env)** (N/A)	$225.52	$225.52	$0.00	0.00%	0.00%
Industrial Transportation (Inc)* (18,165 Ccf)	$16,422.96	$16,678.38	$255.41	1.56%	3.63%
Industrial Transportation (Env) ** (N/A)	$415.52	$415.52	$0.00	0.00%	0.00%
Public Authority (Inc) (501 Ccf)	$434.78	$441.82	$7.04	1.62%	4.00%
Public Authority (Env) (45 Ccf)	$146.20	$146.84	$0.64	0.44%	0.52%
Public Authority Transportation (Inc)** (N/A)	$302.36	$302.36	$0.00	0.00%	0.00%
Public Authority Transportation (Env)** (N/A)	$306.63	$306.63	$0.00	0.00%	0.00%

The above calculations in Table 1 and Table 2 are based on a $0.5170/Ccf cost of gas.
* Transportation customers secure their own gas, so there is no cost of gas reflected in their bills.
** TGS currently has no customers in these classes.

TGS seeks to add a new tariff, RATE SCHEDULE HARV-RIDER, in order to implement a two-year surcharge to recover costs related to the restoration of its system following the impact of Hurricane Harvey. The surcharge will be discontinued after the Company fully recovers the costs that are approved for recovery as part of this Statement of Intent filing.

Persons with specific questions or desiring additional information about this filing may contact TGS at 1-800-700-2442. Complete copies of the filed Statement of Intent, including all proposed rates and schedule changes, are available for inspection at TGS offices, located at 4201 39th Street, Port Arthur, Texas 77642 or 402 33rd Street, Galveston, Texas 77550 or on the Company's website at https://www.texasgasservice.com/newsletters-and-notices/rate-notices. Any affected person within the environs 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. Any affected person within an incorporated area may contact his or her city council. Please reference Gas Utilities Docket No. _________.

Cualquier persona que tenga una pregunta específica o desee obtener información adicional acerca de este asunto, puede contactar a TGS al teléfono 1-800-700-2442. Si desea revisar la Declaración de Intención presentada, incluyendo todos los cambios de tarifas y de clases de tarifas, puede encontrar una copia completa en horas hábiles en las oficinas corporativas de TGS, localizadas en 4201 39th Street, Port Arthur, Texas 77642 or 402 33rd Street, Galveston, Texas 77550, o visitando la página de internet de la Compañía en https://www.texasgasservice.com/newsletters-and-notices/rate-notices. Cualquier persona dentro de la periferia que se vea afectada por los cambios de tarifas propuestos, puede presentar sus comentarios o reclamos por escrito a Docket Services Section, Office of the Hearings Division, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, en cualquier momento dentro de los siguientes 30 días después de la fecha en que los cambios entrarían o entraron en vigencia. Cualquier persona que se vea afectada dentro de las áreas incorporadas puede contactar a su consejo municipal. Por favor refiérase al Expediente de Servicios de Gas (GUD, por sus siglas en inglés) No. ________.

GUD NO. _______

STATEMENT OF INTENT OF	**§**	**BEFORE THE**
TEXAS GAS SERVICE COMPANY, A	**§**	
DIVISION OF ONE GAS, INC., TO	**§**	**RAILROAD COMMISSION**
INCREASE RATES TO RECOVER	**§**	
HURRICANE HARVEY RESPONSE	**§**	**OF TEXAS**
COSTS WITHIN THE GULF COAST	**§**	
SERVICE AREA		

PROTECTIVE ORDER

This Protective Order shall govern the use of all information deemed confidential or highly sensitive confidential information by a party providing information to the Railroad Commission of Texas ("Commission") or responding to discovery requests, including information whose confidentiality may be under dispute in this docket and all dockets consolidated herewith. This order may be modified by the Examiner *sua sponte*, or on advice of the Open Records Coordinator, Office of General Counsel, and the Railroad Commission of Texas.

1. Designation of Protected Materials

Any party or person producing or filing a document, including, but not limited to, records stored or encoded on a computer disk or other similar electronic storage medium, in this proceeding may designate that document, or any portion of it, as confidential by typing or stamping on its face **"PROTECTED MATERIALS PROVIDED PURSUANT TO PROTECTIVE ORDER ISSUED IN GUD NO. _____"** (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 Commission or any other federal or state agency, court, or local government authority subject to the Public Information Act or under the Federal Freedom of Information Act provided however, that any party or person may assert any privilege or exception available under these Acts. Protected materials also shall not include materials that at the time of or prior to disclosure in these proceedings, is or was publicly disclosed, on a non-confidential basis. The disclosure of materials to a party, its customers, or their respective employees, agents, consultants, or counsel in the normal course of business shall not preclude a claim that such materials are protected materials hereunder. Protected materials disclosed by someone other than an employee, agent, or consultant of the originating party in violation of this Protective Order shall not lose their status as protected material as a result of such disclosure.

3. Definition of "reviewing party."

A "reviewing party" is defined for purposes of this Protective Order as a party expressly admitted or that has had a Motion to Intervene granted in GUD No. _____.

4. Definition of "producing party."

A "producing party" is defined for purposes of this Protective Order as a party expressly admitted or that has had a Motion to Intervene granted in GUD No. _____, which has had discovery propounded upon it in any form as provided by applicable law.

5. Access to Protected Materials

A reviewing party shall be permitted access to protected materials only through its authorized representatives. "Authorized representatives" of a party include its counsel of record in this proceeding and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by the party and directly engaged in these proceedings, provided that such person has signed the certification required by Paragraph 8.

6. Designation of Highly Sensitive Protected Materials

The term "highly sensitive protected materials" is a subset of "protected materials." The term refers to, but is not limited to, documents and information the provision of which to the reviewing party or its authorized representatives would: (1) expose the producing party or any of its affiliates to an unreasonable risk of harm, or (2) would result in disclosure of information that would be subject to a privilege against disclosure, a contractual confidentiality agreement or other Protective Agreement or agreement. Highly sensitive protected materials further include, but are not limited to, business operations or financial information that is commercially sensitive. Documents so classified by a producing party shall bear the designation "HIGHLY SENSITIVE PROTECTED MATERIALS PROVIDED PURSUANT TO THE PROTECTIVE ORDER ISSUED IN GUD NO. _____."

7. Restrictions on Copies and Inspection of Highly Sensitive Protected Materials

Highly sensitive protected materials shall be made available for inspection only at the address specified pursuant to Paragraph 9. Additionally, only one copy of highly sensitive protected materials shall be provided to counsel of any party to GUD No. _____ upon written request following completion of the certifications required by Paragraph 8 herein. A party may make one additional copy of reproduced highly sensitive protected materials for use in this proceeding pursuant to this Protective Order. No additional copies of such highly sensitive protected materials may be made, except that additional copies may be made in order to have sufficient copies for introduction of the material into the evidentiary record if the material is to be offered for admission into the record. A record of any copies that are made of highly sensitive protected material shall be kept and a copy of the record shall be sent to the producing party upon request. The record shall include information on the location and the person in possession of the copy. The authorized representatives for the purpose of access to highly sensitive protected materials must be persons who are: (1) counsel for the reviewing party, (2) consultants for the reviewing party working under the direction of the reviewing party's counsel, (3) permanent non-elected employees of municipalities that are parties in GUD No. _____, who have primary responsibility for utility regulation. The authorized representatives for the Commission's Director of Gas Services or the State of Texas for the purpose of access to these materials shall consist of its respective counsel of record in this docket and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by those agencies and directly engaged in this docket. Limited notes may be made of highly sensitive protected materials, and such notes shall themselves be treated as highly sensitive protected material unless such notes are restricted to a description of the document and a general characterization of its subject matter in a manner that does not include any substantive information contained in such highly sensitive protected materials.

8. Required Certification

Each person who inspects the protected materials shall, before such inspection, agree in writing to follow certification set forth in Exhibit A to this Order:

> I certify my understanding that the protected materials are provided to me pursuant to the terms and restrictions of the Protective Order in GUD No. _____, and that I have been given a copy of it and have read the Protective Order and agree to be bound by it. I understand that the contents of the protected materials, any notes, memoranda, or any other form of information regarding or derived from the protected materials shall not be disclosed to anyone other than in accordance with the Protective Order and shall be used only for the purpose of the proceeding in GUD No. _____. I acknowledge that the obligations imposed by this certification are pursuant to a ruling issued by the Examiners in this docket. However, if the information contained in the protected materials is obtained from independent sources that did not obtain such information from documents obtained in this docket, the understanding stated herein shall not apply.

In addition, reviewing parties who are permitted access to highly sensitive protected material under the terms of this ruling shall, before inspection of such materials, agree in writing to the following certification set forth in Exhibit A to this Protective Order:

> I certify that I am eligible to have access to highly sensitive protected materials under the terms of the Protective Order in GUD No. _____.

A copy of each signed certification shall be provided to counsel for the party asserting confidentiality. Except for highly sensitive protected materials, any authorized representative may disclose protected materials to any other person who is an authorized representative, provided that, if the person to whom disclosure is to be made has not executed and provided for delivery of a signed certification to the party asserting confidentiality, that certification shall be executed prior to any disclosure. An authorized representative may disclose highly sensitive protected material to other reviewing representatives who are permitted access to such materials and have executed the additional certification required for persons who receive access to highly sensitive protected material. In the event that any authorized representative to whom protected materials are disclosed ceases to be engaged in these proceedings, access to protected materials by that person shall be terminated and all notes or memoranda or other information derived from the protected material shall be returned to the party on whose behalf that person was acting. Any person who has agreed to either or both of the foregoing certifications shall continue to be bound by the provisions of this Protective Order, even if no longer engaged in these proceedings. Parties who assert confidentiality shall maintain a list of persons who sign a certification pursuant to this Paragraph.

9. Voluminous Materials

(a) Voluminous protected materials which exceed eight linear feet shall be made available for inspections in its normal repository between the hours of 9:30 a.m. and 5:00 p.m., Monday through Friday (except holidays) in accordance with the Texas Rules of Civil Procedure. A party shall notify the other parties of the address at which the voluminous data will be produced simultaneously with the production of such data. For purposes of this Protective Order voluminous materials or data shall mean responses to a particular question or subpart that consist of one hundred pages or more in the aggregate.

(b) Except for highly sensitive protected materials as provided for in Paragraph 7, and for protected materials that are voluminous, the party asserting confidentiality shall provide a party one copy of the protected materials upon receipt of the signed certifications described in Paragraph 8. Except as provided above for highly sensitive protected materials, parties may take notes regarding the information contained in protected materials made available for inspection pursuant to Paragraph 9(a). Only one copy of such protected materials shall be reproduced for each party. Parties shall make a diligent, good-faith effort to limit the amount of copying requested to only that which is appropriate for purposes of this proceeding. Notwithstanding the foregoing provisions of this Paragraph 9(b), a party may make further copies of reproduced protected materials for use in this proceeding pursuant to this Protective Order, but a record shall be maintained as to the documents produced and the number of copies made, and upon request, the party shall provide the party asserting confidentiality with a copy of that record.

10. Availability for Purposes of this Filing

All protected materials shall be made available to the parties solely for the purposes of this proceeding. Protected materials, as well as a party's notes, memoranda, or other information regarding, or derived from the protected materials are to be treated confidentially by the parties and shall not be disclosed or used by the party except as permitted and provided in this Protective Order. Information derived from or describing the protected materials shall be maintained in a secure place and shall not be placed in the public or general files of the party except in accordance with the provisions of this Protective Order. A party must take all reasonable precautions to ensure that the protected materials, including notes and analysis made from protected materials, are not viewed or taken by any person other than an authorized representative of the party.

All non-voluminous protected materials may be reviewed only during the "reviewing period," which period shall commence upon issuance of this Protective Order and continue until conclusion of the plenary jurisdiction of the Commission in this proceeding. The "reviewing period" shall reopen if the Commission regains jurisdiction due to a remand as provided by law. Protected materials that are admitted into the evidentiary record or accompanying the evidentiary record as offers of proof, may be reviewed while this proceeding or any appeals hereof are pending.

11. Treatment of Protected Materials

(a) If a party tenders for filing any written testimony, exhibit, brief, or other submission that quotes from protected materials or discloses the confidential content of protected materials, the confidential portion of such testimony, exhibit, brief, or other submission shall be sealed and shall be filed and served in accordance with the appropriate procedures utilized by the Commission. The Examiners may subsequently, on their own motion or on motion of a party, issue a ruling respecting whether or not the inclusion, incorporation, or reference to protected materials is such that the written testimony, exhibit, brief, or other submission should remain under seal.

(b) Any party or person giving testimony in this proceeding may designate those portions of his or her testimony deemed to be confidential materials in accordance with Paragraph 1 of this Protective Order by advising the Examiner of such fact. In that event, the Examiner shall, on a case-by-case basis, devise procedures which are fair to all parties without unduly burdening the record in this docket.

(c) All protected materials filed with the Commission, the Examiner, any other judicial or administrative body in support of or as part of a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers.

12. Changes to Protective Order

Nothing herein restricts the party seeking protected material and the party producing the protected material from agreeing to other procedures/methods for handling of protected material, including highly sensitive protected material. In addition, each party shall have the right to seek changes in this Protective Order as appropriate from the Examiners, the Commission, or the courts. Nothing herein shall prevent any party from opposing efforts to seek changes to this ruling.

13. Judicial Findings

In the event that the Examiner at any time in the course of this proceeding finds that all or part of the protected materials are not confidential, by finding, for example, that such materials have entered the public domain, those materials shall nevertheless be subject to the protection afforded by this ruling for three full working days, unless otherwise ordered, from the latest of (i) the date of receipt by the party asserting confidentiality of the Examiner's order, or (ii) the date of a final and appealable Commission order denying an appeal filed within the three full working day period from the Examiner's order; or (iii) approval of such order by operation of law following the filing of such an appeal. Neither the party asserting confidentiality nor any reviewing party waives its right to seek additional administrative or judicial remedies after the Commission's denial of any appeal.

14. Disclosure of Protected Materials

(a) During the pendency of GUD No. _____ at the Commission, in the event that a party wishes to disclose protected materials to any person to whom disclosure is not authorized by this Protective Order, or wishes to have changed the designation of certain information or material as protected materials by alleging, for example, that such information or material has entered the public domain, such party shall first file and serve on all parties written notice of such proposed disclosure or request for change in designation, identifying with particularity each of such protected materials. In the event that the party asserting confidentiality wishes to contest such proposed disclosure or request for change in designation, that party shall file with the Commission its objection to such proposal, with supporting sworn affidavits, if any, within five working days after receiving such notice of proposed disclosure or request for change in designation. Failure of that party to file such an objection within this period shall be deemed a waiver of objection to the proposed disclosure or request for change in designation. Upon the request of either the producing party or reviewing party or upon the Examiner's own initiative, the Examiner may conduct a prehearing conference. If either the producing or reviewing party wishes to submit materials in question for an in camera inspection, it shall do so at the time of filing its written notice or objection to disclosure. Responses to such an objection, with supporting affidavits, if any, shall be filed within five working days after receipt of the objection. The Examiner will determine whether the proposed disclosure or change in designation is appropriate. The burden is on the party asserting confidentiality to show that such proposed disclosure or change in designation should not be made. If the Examiner determines that such proposed disclosure or change in designation should be made, disclosure shall not take place earlier than three full working days after such determination unless otherwise ordered. No party waives any right to seek additional administrative or judicial remedies concerning such Examiner's ruling. As long as the periods set out in this Protective Order for filing the pleadings described above for consideration by the Examiner and for challenging the determination of the Examiner or the Commission have not expired and while a challenge is pending, the protected materials shall maintain the confidential treatment and status provided for in this Protective Order.

(b) All protected materials shall be afforded the confidential treatment and status provided for in this Protective Order during the period an appeal on an Examiner's ruling is pending before the Commission and during the periods for challenging the various orders.

(c) All notices, applications, responses, or other correspondence shall be made in a manner that protects protected materials from unauthorized disclosure.

15. Objection to Protected Materials

Nothing in this ruling shall be construed as precluding any party from objecting to the use of protected materials on grounds other than confidentiality, including the lack of required relevance. Nothing in this ruling shall be construed as an agreement by any party that the protected materials are entitled to confidential classification.

16. Acts upon Conclusion of Proceeding

Following the conclusion of these proceedings, each party must, no later than thirty days following receipt of the notice described below, destroy or return to the party asserting confidentiality all copies of the protected materials provided by that party pursuant to this Protective Order and all copies reproduced by a reviewing party, and counsel for each party must provide to the party asserting confidentiality a verified certification that, to the best of his or her knowledge, information, and belief, all copies of notes, memorandum, and other documents regarding or derived from the protected materials (including copies of protected materials) that have not been so returned, if any, have been destroyed, other than notes, memoranda, or other documents which contain information in a form which, if made public, would not cause disclosure of protected materials. Promptly following the conclusion of this proceeding, counsel for the party asserting confidentiality will send a written notice to all parties, reminding them of their obligations under this Paragraph. Nothing in this Paragraph shall prohibit counsel for each party from retaining two copies of any filed testimony, exhibit, brief, application for rehearing, or other pleading which refers to protected materials provided that any such protected materials retained by counsel shall remain subject to the provisions of this ruling. As used in this Paragraph, "conclusion of this proceeding" refers to the exhaustion of available appeals, or the running of the time for making of such appeals, as provided by applicable law. If, following any appeal, the Commission conducts a remand proceeding, then "the conclusion of these proceedings" is extended by the remand to the exhaustion of available appeals, or the running of the time for the making of such appeals, as provided by applicable law. If, following any appeal, the Commission conducts a remand proceeding, then the "conclusion of this proceeding" is extended by the remand to the exhaustion of available appeals of the remand or the running of time for making such appeals of the remand, as provided by applicable law.

17. Compliance with Legal Requirements

This Protective Order is subject to the requirements of the Public Information Act, the Open Meetings Act, and any other applicable law, provided that parties subject to those acts will give the party asserting confidentiality notice, if possible under those acts, prior to disclosure pursuant to those acts.

18. Effect of Court Order

If required by order of a government or judicial body, the party may release to such body the confidential information required by such order, provided, however, the party agrees that prior to such disclosure, it shall promptly notify the party asserting confidentiality of the order and allow such party sufficient time to contest release of the confidential information; provided, further, the party shall use its best efforts to prevent such confidential information from being disclosed.

The term "best efforts" as used in the preceding paragraph requires that the party's attempt to ensure that disclosure is not made by its employees or authorized representatives unless such disclosure is pursuant to a final order of a governmental or judicial body or written opinion of the Attorney General which was sought in compliance with V.T.C.A., Government Code §552.301 (Public Information). The party is not required to delay compliance with a lawful order to disclose such information but is simply required to timely notify the party asserting confidentiality, or its counsel, that it has received a challenge to the confidentiality of the information and that the reviewing party will either proceed under the provisions of §552.301 of the Texas Government Code or intends to comply with the final governmental or court order.

19. Effect of Violation of Court Order

In the event of a breach of the provisions contained in Paragraph 18, the party asserting confidentiality may not have an adequate remedy in money or damages, and accordingly, may 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 Order in GUD No. _____, and that I have been given a copy of it and have read the Protective Order and agree to be bound by it. I understand that the contents of the protected materials, any notes, memoranda, or any other form of information regarding or derived from the protected materials shall not be disclosed to anyone other than in accordance with the Protective Order and shall be used only for the purpose of the proceeding in GUD No. _____. I acknowledge that the obligations imposed by this certification are pursuant to a ruling issued by the Examiners in this docket. However, if the information contained in the protected materials is obtained from independent sources that did not obtain such information from documents obtained in this docket, the understanding stated herein shall not apply.

Signature	Party Represented
Printed Name	Date

Additional certification for highly sensitive protected materials:

I certify that I am eligible to have access to highly sensitive protected materials under the terms of the Protective Order in GUD No. _____.

Signature	Party Represented
Printed Name	Date

Texas Gas Service, a Division of ONE Gas, Inc.
Gulf Coast Service Area
Hurricane Harvey Surcharge

Exhibit G
Schedule 1

Surcharge Calculation

Line No.	Description	Account	Amount
1	Labor	091.7550.7550.8740100.10.000000	192,570
2	Overtime	091.7550.7550.8740100.16.000000	335,747
3	Supplies and Expenses	091.7550.7550.8740100.21.000000	9,775
4	Contractor	091.7550.7550.8740100.23.000000	15,999
5	Tools	091.7550.7550.8740100.25.000000	122
6	Freight	091.7550.7550.8740100.26.000000	1,605
7	Communication	091.7550.7550.8740100.32.000000	2,909
8	Restoration	091.7550.7550.8740100.34.000000	7,920
9	Travel	091.7550.7550.8740100.35.000000	135,966
10	Utilities	091.7550.7550.8740100.37.000000	723
11	Meals	091.7550.7550.8740100.42.000000	47,225
12	Employee Expenses - Other	091.7550.7550.8740100.44.000000	12,467
13	Auto Loading	091.7550.7550.8740100.45.000000	30,228
14	Stores Overhead	091.7550.7550.8740100.50.000000	(1,530)
15	Stores Issues and Returns	091.7550.7550.8740100.51.000000	123,867
16	Direct Materials Purchases	091.7550.7550.8740100.52.000000	72,543
17	Permits	091.7550.7550.8740100.72.000000	753
18	Subtotal Expenses		988,890
	Less:		
19	Meals & Hotel Over Limit (1)		(32,102)
20	Insurance Settlement		(242,400)
21	Subtotal Deductions		(274,501)
22	Total to Recover		714,389
23	Recovery period (years)		2
24	Annual Recovery		357,194
25	Annual Volumes (Ccf)		25,403,682
26	Surcharge Rate per Ccf		0.01406

(1) Removal of meals over $25 per person per meal and hotels over $150 per night.

Texas Gas Service, a Division of ONE Gas, Inc.
Gulf Coast Service Area
Hurricane Harvey Surcharge

Exhibit G
Schedule 2

Summary of Expenditures

Line No.	Description	AUG-17	SEP-17	OCT-17	NOV-17	DEC-17	JAN-18	FEB-18	MAR-18	Total
1	Labor		159,391	33,178						192,570
2	Overtime		291,070	44,677						335,747
3	Supplies and Expenses		2,077	7,853	4		107	2,192	(2,457)	9,775
4	Contractor				15,999					15,999
5	Tools			102			20			122
6	Freight		250	1,163	111	81				1,605
7	Communication			2,909						2,909
8	Restoration			7,920						7,920
9	Travel		1,468	34,447	72,122	10,125	11,787	6,018		135,966
10	Utilities		54	102	452		34	82		723
11	Meals		147	40,328	3,653	796	2,058	244		47,225
12	Employee Expenses - Other		1,879	9,949	299	116	224			12,467
13	Auto Loading		25,827	4,401						30,228
14	Stores Overhead	12,428	(11,238)	(3,096)			376			(1,530)
15	Stores Issues and Returns	44,325	122,499	(44,981)			2,023			123,867
16	Direct Materials Purchases	1,869	8,475	30,072	9,936	7,642	461	14,089	-	72,543
17	Permits			753						753
18	Total	58,622	601,899	169,778	102,576	18,758	17,091	22,624	(2,457)	988,890

SCHEDULE WORKPAPERS

Schedule Workpapers are voluminous and are being provided in electronic format.

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF STACEY MCTAGGART

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

1. "My name is Stacey McTaggart. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Director of the Rates and Regulatory Compliance Department of 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.

Stacey McTaggart

SUBSCRIBED AND SWORN TO BEFORE ME by the said Stacey McTaggart on this 25th day of November, 2019

MARY L PENA
NOTARY PUBLIC
ID# 11652311
State of Texas
Comm. Exp. 05-13-2023

Notary Public in and for the State of Texas

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

JANET L. BUCHANAN

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

DIRECT TESTIMONY OF JANET L. BUCHANAN

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Janet L. Buchanan and my business address is 7421 W. 129th Street, Overland Park, Kansas 66213.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am employed by Kansas Gas Service, a Division of ONE Gas, Inc., ("ONE Gas") as a Director of Rates and Regulatory Reporting.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Arts degree and Master of Arts degree in economics from the University of Kansas. From June 1993 through August 1998 and from May 1999 through August 2011, I worked for the Kansas Corporation Commission in various positions with varying levels of responsibility for examining rates for natural gas, electric and telecommunications utilities, researching current policy issues within the industries, and managing projects.[1] Positions held include: Utility Rates Analyst, Senior Research Economist, Managing Research Economist, Telecommunications Economist, Senior Telecommunications Analyst, Senior Managing Research Analyst, Chief of Telecommunications and Chief of Energy Efficiency and Telecommunications. In September 2011, I joined Texas Gas Service Company, a Division of ONE Gas, Inc. ("TGS" or the "Company"), as a

[1] I worked for the Kansas Department of Revenue as a Policy and Program Analyst providing the fiscal impact of proposed changes in the mineral severance tax and the motor fuel tax from September 1998 through April 1999.

Manager of Rates and Regulatory Analysis. I was promoted to my current position in October 2017.

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

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I explain and support the revenue adjustments used to develop the requested system-wide revenue requirement for TGS's proposed Central-Gulf Service Area ("CGSA"), which is the proposed consolidation of the existing Central Texas Service Area ("CTSA) and Gulf Coast Service Area ("GCSA") and the City of Beaumont, Texas.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. I am sponsoring Schedules G-1 through G-3 for the proposed CGSA. In addition to schedules that reflect the Company's requested consolidation for the proposed CGSA, TGS is also providing stand-alone schedules for the CTSA and GCSA. The cost of service for customers in the City of Beaumont, Texas is included in and part of the GCSA.

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

II. REVENUE ADJUSTMENTS

Q. WHAT ADJUSTMENTS TO REVENUE ARE YOU SPONSORING?

A. I am sponsoring the adjustments to Gas Sales and Transportation Revenue listed on Schedules G-1, G-2 and G-3. Schedule G-1 presents the cost of gas expense and the cost of gas revenues that are removed from the Company's per books test year expenses and revenues. These adjustments are necessary because gas costs are recovered via the Cost of Gas Clause ("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 for the purpose of setting rates in this proceeding. 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 statement of intent.

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, which is sponsored by Company witness Marie J. Michels.

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 June 30, 2019, is reported 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 recorded on line 3.

Q. PLEASE EXPLAIN THE WEATHER NORMALIZATION ADJUSTMENT ON LINE 4 OF SCHEDULE G-2.

A. TGS currently has weather normalization adjustment ("WNA") clauses in effect for the existing CTSA, the existing GCSA, and for the City of Beaumont. In this statement of intent, TGS proposes a WNA clause that will be applicable to the proposed CGSA. Revenue collected or refunded through the WNA clause 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 CGSA 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 clause during the test year. This is accomplished through the adjustment of $376,216 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. It 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. Consistent with the practice in its other service areas, 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 June 30, 2019.

Q. WHY WAS A PERIOD OF TEN YEARS SELECTED?

A. A ten-year period is consistent with what has been approved in the Company's other service areas pursuant to Railroad Commission of Texas ("Commission") orders issued in Gas Utilities Docket ("GUD") No. 10506, which was fully litigated, and GUD Nos. 9988, 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. 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 CGSA was developed based on data from four weather stations: (1) Austin Camp Mabry ("KATT"); (2) San Antonio International Airport ("KSAT"); (3) Galveston, Scholes Field ("KGLS"); and (4) Beaumont/Port Arthur Southeast Texas Regional Airport ("KBPT"). A separate analysis is conducted for each customer class in the proposed CGSA 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 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

[2] *See, e.g., Statement of Intent filed by Atmos Energy Corp., to Increase Gas Utility Rates Within the Unincorporated Areas Served by the Atmos Energy Corp., Mid-Tex Division*, GUD No. 10170 (Dec. 4, 2012).
[3] *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.").

TGS in prior rate cases.[4] This volume adjustment was then priced at the test year tariff rates to yield the revenue adjustment, a $(745,492) decrease to test year base sales revenues, as shown on line 5 of Schedule G-2. This adjustment decreases base sales revenues in recognition of the fact that the volumes and resulting revenues for weather stations KATT and KSAT were abnormally high because temperatures in the test year period were 13 percent colder than normal, partially offset by lower than normal volumes and revenues for weather stations KGLS and KBPT due to temperatures which were 6 percent warmer than normal. On a volume weighted basis among the four weather stations, weather was approximately 11 percent colder than normal during the test year. By adjusting sales volumes downward to reflect normal weather conditions in the proposed combined service area 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 $4,688 to account for the net effect of revenues gained or lost from commercial, industrial, and public authority customers in the proposed CGSA that switched between gas

[4] This methodology was utilized in the Company's Gulf Coast Service Area in 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; and the Borger-Skellytown Service Area in GUD No. 10766.

sales and transportation service during the test year. Because the customers' switch to or from transportation 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 (LOSS) 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/loss patterns and adjusts customer counts accordingly. For each customer class within the proposed CGSA, this adjustment annualizes the growth (or loss) in customers that occurred during the twelve months ended June 30, 2019 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. The change in customers as of June 30, 2019, was calculated by comparing the number of active customers at June 30, 2018, to the number of active customers at June 30, 2019. The adjustment shown on line 7 on Schedule G-2 annualizes the growth in the proposed CGSA in the amount of $369,076.

Q. PLEASE EXPLAIN THE POST-TEST-YEAR CUSTOMER GROWTH REVENUE ADJUSTMENT ON LINE 8 OF SCHEDULE G-2.

A. This adjustment calculates post-test-year growth through September 30, 2019, for the proposed CGSA assuming a growth rate equal to that experienced during the test year. This adjustment was made to be consistent with the Company's proposed known and measurable adjustment to plant to include capital expenditures for projects that were placed into service by September 30, 2019. The overall increase to base sales revenue is $92,591 as shown on line 8 of Schedule G-2.

Q. PLEASE EXPLAIN THE REVENUE ADJUSTMENT ON LINE 9 OF SCHEDULE G-2.

A. On June 3, 2019, TGS implemented an interim rate adjustment (also known as a "GRIP" adjustment) in the City of Austin, and on June 14, 2019, the GRIP adjustment was implemented for the remaining incorporated areas and environs of the CTSA. The annualization of this revenue impact over the entire test year results in a $5,074,960 increase to base sales revenues. Additionally, on September 26, 2019, TGS implemented a GRIP adjustment for the environs areas of the GCSA, which when annualized for the test year results in a $5,346 increase to base sales revenues. The combined impact for the proposed CGSA is a $5,080,306 increase to base sales revenues.

Q. PLEASE EXPLAIN THE REVENUE ADJUSTMENT ON LINE 10 OF SCHEDULE G-2.

A. On July 29, 2019, TGS implemented a Cost of Service Adjustment ("COSA") for the incorporated areas of the GCSA. The annualization of this revenue impact over the entire test year results in a $138,315 increase to base sales revenues.

Q. PLEASE EXPLAIN THE REVENUE ADJUSTMENT ON LINE 11 OF SCHEDULE G-2.

A. This adjustment addresses revenue associated with unmetered gas service for public street lighting. As noted by Company witness Christy M. Bell, TGS is proposing a tariff for unmetered street lighting in the proposed CGSA. If the proposed tariff is approved, the test year revenue will be increased by $2,655 as shown on line 11 of Schedule G-2 to account for 66 existing unmetered gas street lamps in the City of Galveston.

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 $5,318,354, as shown on line 12 of Schedule G-2. This results in a total Base Sales Revenue amount, as adjusted, of $96,912,395 as shown on line 13 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 increases transportation revenues by $1,652.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO NORMAL WEATHER ON LINE 3 OF SCHEDULE G-3.

A. As previously described, this adjustment decreases transportation revenue in recognition of the fact that the net volumes and resulting net revenues in the Company's proposed CGSA were abnormally high because temperatures during the test year were colder than normal. This adjustment decreases transportation revenue by $(79,118).

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 4 OF SCHEDULE G-3.

A. Line 4 reflects a revenue adjustment of $(6,650) to annualize the net effect of revenue lost or collected from transportation customers that switched to or from gas sales service during the test year. As noted above, the Company is making a similar adjustment to gas sales service revenues to reflect the movement of these customers to or from transportation service. Because the customers' switch between gas sales and transportation 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 of Schedule G-3 addresses potential changes to TGS transportation revenues as a result of the recent acquisition that created ONE Gas Pipeline Company. The adjustment increases transportation revenues by $323,289.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 6 OF SCHEDULE G-3.

A. The adjustment on line 6 of Schedule G-3 increases transportation revenue by $4,062 to annualize the impact of a new public authority transportation customer that began service during the test year.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 7 OF SCHEDULE G-3.

A. The adjustment on line 7 of Schedule G-3 decreases base transportation revenue by $(14,342) and removes the revenue of commercial, public authority, and public school space heating transportation customers that terminated service during the test year.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 8 OF SCHEDULE G-3.

A. As previously discussed, TGS implemented an interim GRIP adjustment in the incorporated and environs areas of the CTSA, as well as the environs areas of the GCSA during the test year. In order to recognize the annualized revenue impact of the implementation of these GRIP adjustments, $127,541 has been added to transportation revenues.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 8 OF SCHEDULE G-3.

A. As previously discussed, TGS implemented a COSA during the test year for the incorporated areas of the GCSA. In order to recognize the annualized impact of the implementation of the COSA, $1,441 has been added to transportation revenues.

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 $357,875, 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 reflects the revenue impact of adding and changing service fees in the proposed CGSA. As described in the direct testimony of Ms. Bell, these changes will increase certain service fees and decrease other fees. These changes will have the effect of increasing the revenues the Company would otherwise recover under its existing service fees. To account for these changes, an increase of $277,029 to test year revenues is included on line 13 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 and insurance reimbursements related to the damage from Hurricane Harvey.

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 $347,618 decrease to revenues.

Q. PLEASE EXPLAIN THE ADJUSTMENT ON LINE 17 OF SCHEDULE G-3.

A. Line 17 of Schedule G-3 reflects a decrease to test year revenues of $61,878 to remove insurance reimbursements related to the loss of revenues as a result of

Hurricane Harvey. Because this revenue is non-recurring in nature it has been excluded.

Q. WHAT IS THE TOTAL TRANSPORTATION, SERVICE FEES AND OTHER UTILITY REVENUE AS ADJUSTED?

A. As shown on line 19 of Schedule G-3, the total amount as adjusted is $12,091,812.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF KANSAS §
§
COUNTY OF JOHNSON §

AFFIDAVIT OF JANET BUCHANAN

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

1. "My name is Janet Buchanan. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Director of the Rates and Regulatory Reporting, Kansas 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.

Janet Buchanan

Janet Buchanan

SUBSCRIBED AND SWORN TO BEFORE ME by the said Janet Buchanan on this 4th day of December, 2019

Notary Public in and for the State of Kansas

STATE OF KANSAS NOTARY PUBLIC

STEPHANIE FLEMING
My Appointment Expires
June 5, 2022

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

GRACIE GUERRA

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

DIRECT TESTIMONY OF GRACIE GUERRA

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gracie Guerra and my business address is 1301 South MoPac Expressway, Suite 400, Austin, Texas 78746.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a Rate Analyst II for Texas Gas Service Company ("TGS" or the "Company"), which is a Division of ONE Gas, Inc. ("ONE Gas").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Business Administration with a major in Accounting from Texas A&M University-Kingsville in 2004. I began my career with TGS in September 2017 as a Rate Analyst I. Prior to my employment with TGS, I was a Staff Accountant for Cheryl Janner, CPA in Bryan, Texas from August 2006 to April 2010 and as a Shared Services Lead at Cabela's Inc., in December 2009 until September 2017. From August 2004 to August 2006, I worked as an Assistant Manager for Security Finance, Inc.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I provided written testimony in Gas Utilities Docket ("GUD") No. 10766 before the Railroad Commission of Texas ("Commission").

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

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony summarizes the Direct costs attributed to the proposed Central-Gulf Service Area ("CGSA") in the Company's cost of service calculation that demonstrate the Company's need for a rate change in the proposed CGSA. I also describe the portion of the Company's requested rate base amounts related to proposed CGSA Direct costs. Company witness Mindy R. Edwards supports TGS Division and Corporate rate base adjustments in her direct testimony.

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 Ms. Mindy R. Edwards
Schedule B-1 M&S	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 Cyndi King
Schedule B-6 CWC	Co-Sponsor with Timothy S. Lyons
Schedule B-7 Deposits	Sponsoring
Schedule B-8 Advances	Sponsoring
Schedule B-9 ADIT	Co-Sponsor with Janet M. Simpson
Schedule C-1 (CCNC)	Co-Sponsor with Ms. Mindy R. Edwards
Schedule C (Plant)	Co-Sponsor with Ms. Mindy R. Edwards and Ms. Allison N. Edwards
Schedule D (Reserves)	Co-Sponsor with Ms. Mindy R. Edwards
Schedule F (Federal Income Tax)	Sponsoring

The schedules that I address in my testimony are for the Company's proposed CGSA. In addition to schedules that reflect the Company's requested consolidation for the CGSA, TGS is also providing stand-alone schedules for the Central Texas and Gulf Coast Service Areas ("CTSA" and "GCSA"). The cost of service information for customers within the City of Beaumont is included in and a part of the GCSA.

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

II. OVERVIEW OF COST OF SERVICE CALCULATION

Q. HOW DID THE COMPANY CALCULATE THE REQUESTED RATES FOR THE PROPOSED CGSA?

A. In calculating the requested rates, the Company used the cost of providing service to the entire proposed CGSA 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 Statement of Intent contains the cost of service schedules that, taken together, show the calculation of the Company's revenue requirement in the proposed CGSA. The Company's methodology in this Statement of Intent 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.[1]

[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 Galveston Service Area (GSA) and South Jefferson County*

Q. WHAT TEST YEAR DID TGS USE TO CALCULATE THE REVENUE REQUIREMENT FOR THIS STATEMENT OF INTENT?

A. The Company calculated its revenue requirement based on the twelve-month period ending June 30, 2019, adjusted for certain known and measurable changes through September 30, 2019.

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 operation of the Company's system within the proposed CGSA as demonstrated by the schedules included with the Statement of Intent, the supporting testimony and workpapers.

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 Statement of Intent. For example, adjusted rate base, as calculated in Schedule B, is multiplied by the rate of return, calculated in Schedule

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Service Area (SJCSA), GUD No. 10488, Final Order (May 3, 2016); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Area (EPSA), Permian Service Area (PSA), and Dell City Service Area (DCSA),* GUD No. 10506, consol., Final Order (Sept. 27, 2016); *Statement of Intent of Texas Gas Service Company (TGS), a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area (CTSA) and South Texas Service Area (STSA)*, GUD No. 10526, Final Order (Nov. 15, 2016); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, GUD No. 10656, Final Order (March 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 (June 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 Borger Skellytown Service Area*, GUD No. 10766 (Feb. 5, 2019).

E, to derive the required return of $37,529,690. 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) of $125,831,431. A comparison of this revenue requirement to adjusted revenues, from Schedule G, demonstrates that the Company's current rates in the proposed CGSA produce a level of revenues that is $16,827,224 lower (before gross-up for additional uncollectible expense and Texas franchise tax) than the Company's cost of providing service in the proposed CGSA. After gross-up for additional uncollectible expense and Texas franchise tax, the revenue deficiency on a system-wide basis within the proposed CGSA is $17,046,666.

III. <u>RATE BASE</u>

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 CGSA. 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 "construction completed 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.

A. CCNC is different from Construction Work in Progress ("CWIP"). Title 16 Tex. Admin. Code 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.[2]

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 $657,555,686 on Schedule B is the sum of the adjusted plant balances shown on Schedule C through the test year ended June 30, 2019, adjusted for certain known and measurable changes as of September 30, 2019 for: (1) Direct proposed CGSA plant; (2) the proposed CGSA's allocated portion of TGS Division plant balances, and (3) allocated ONE Gas corporate plant balances. The adjusted CCNC balance of $80,305,627 on Schedule B is the sum of the adjusted CCNC balances shown on Schedule C-1 through the test year ended June 30, 2019, adjusted for certain known and measurable changes as of

[2] *Petition of the De Novo Review of the Denial of the Statements of Intent filed by Texas Gas Service Company by the Cities of El Paso, Anthony, Clint, Horizon City, Socorro, and Village of Vinton, Texas*, GUD No. 9988, Final Order (Dec. 14, 2010); *Statement of Intent of Texas Gas Service Company to Change Rates Within the Environs of the South Texas Service Area,* GUD No. 10217, Final Order (Mar. 26, 2013); GUD No. 10488, Final Order; and GUD No. 10506, Final Order.

September 30, 2019 for: (1) Direct proposed CGSA balances; (2) the proposed CGSA's allocated portion of TGS Division balances; and (3) allocated ONE Gas Corporate CCNC balances.

Q. WILL CWIP BALANCES REMAIN IN THE COST OF SERVICE CALCULATION?

A. No. The Company is not ultimately requesting the inclusion of CWIP in its cost of service calculation. The Company included September 30, 2019 CWIP balances as an adjustment to CCNC. TGS will true-up net plant to exclude any plant that is not used and useful at December 31, 2019 and will provide the updated amounts of plant in service, CCNC and accumulated reserves balances by February 14, 2020.

Q. PLEASE EXPLAIN HOW THE PER BOOK BALANCE OF PLANT IN SERVICE WAS CALCULATED.

A. The Per Book Plant in Service balance as of June 30, 2019 of $648,474,688 on Schedule C (line 4) results from three component parts: (1) $621,269,889, the per book balance of proposed CGSA Direct Plant in Service; (2) $2,231,250, the proposed CGSA's allocated portion of TGS Division per book Plant in Service; and (3) $24,973,550, the proposed CGSA's allocated portion of ONE Gas Corporate per book Plant in Service. Ms. Mindy Edwards sponsors the TGS Division and ONE Gas Corporate amounts and the reasonableness of these amounts.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO THE PER BOOK PLANT IN SERVICE BALANCES?

A. Yes, adjustments were made to the per book proposed CGSA Direct Plant in Service balance to remove any plant additions, transfers or retirements mistakenly coded to the proposed CGSA, and to remove plant that will retire once new amortization rates are implemented. An adjustment to capitalized meal and hotel costs was made as described in the testimony of Company witness Allison N. Edwards. In addition, the Company included adjustments to add plant balances for ONE Gas Pipeline Company ("OPC") and post-test year plant through September 30, 2019. The total amount of adjustments to the proposed CGSA Direct per book Plant in Service balance equals $11,586,707. The Company also adjusted TGS Division and ONE Gas Corporate per book Plant in Service balances as identified and sponsored by Ms. Mindy Edwards.

Q. PLEASE DESCRIBE THE ADDITION OF OPC PLANT BALANCES.

A. There are no test year per book costs related to OPC, but TGS has made known and measurable changes to adjusted test year costs for OPC related capital investment which are reflected on Workpaper C.a. In addition, Company witnesses Shantel Norman and Stacey L. McTaggart address issues related to OPC in their testimony.

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 $657,555,686 on Schedule C (line 4) results from three components: (1) $632,856,596, the adjusted proposed CGSA Direct Plant in Service balance; (2) $2,056,706, the proposed CGSA's allocated portion of the adjusted TGS Division Plant in Service balance; and (3) $22,642,384, the proposed CGSA's allocated portion of the adjusted ONE Gas Corporate Plant in Service balance. Ms. Mindy Edwards 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 $60,337,698 on Schedule C-1 (line 4) results from two component parts at June 30, 2019: (1) $59,925,068, the per book balance of proposed CGSA Direct CCNC; (2) $13,102, the proposed CGSA's allocated portion of the adjusted TGS Division Plant in Service balance; and (3) $399,529, the proposed CGSA's allocated portion of ONE Gas Corporate per book CCNC. Ms. Mindy Edwards 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, the Company removed capitalized meal and hotel expenses consistent with the adjustment discussed in Ms. Allison Edwards' testimony. In addition, as previously discussed, the Company included post-test year CCNC and CWIP at September 30, 2019. TGS will true-up net plant to exclude any plant that is not used and useful at December 31, 2019 and will provide updated amounts of plant in service, CCNC and accumulated reserves balances by February 14, 2020. The total adjustments to the proposed CGSA Direct per book CCNC balance equals $14,842,596. Ms. Mindy Edwards explains and supports adjustments made to ONE Gas Corporate CCNC per book balances.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED THE ADDITION OF KNOWN AND MEASURABLE PLANT PLACED IN SERVICE AFTER A TEST YEAR END?

A. Yes, it has. The Commission approved the Company's inclusion of known and measurable additions to used and useful plant beyond the test year in GUD Nos. 9988, 10217, 10488, and 10506.

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 June 30, 2019 of $(187,235,275) on Schedule D contains: (1) $(177,705,899), the per book proposed CGSA Direct Reserve balance; (2) $(125,324), the proposed CGSA allocated portion of the TGS Division reserve balance; and (3) $(9,404,053), the proposed CGSA allocated portion of the ONE Gas Corporate reserve balance. Adjustments were made to the per book proposed CGSA Direct Reserve balance to remove any plant additions, transfers or retirements mistakenly coded to the proposed CGSA, and to remove plant that will retire once new amortization rates are implemented. The Company also included an adjustment to add reserve balances for OPC through September 30, 2019. In addition, as previously discussed, the Company included post-test year reserves and Retirement Work in Progress (RWIP) at September 30, 2019. TGS will true-up net plant to exclude any plant that is not used and useful at December 31, 2019 and will provide updated amounts of plant in service, CCNC and accumulated reserves balances by February 14, 2020. Finally, the Company has made two adjustments 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 2015 and 2019 depreciation studies. The adjustment in relation to the 2015 depreciation study 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. A similar issue was identified in Dr. White's 2019 depreciation study and a similar, proforma adjustment has been made in this filing. Dr. White discusses the 2019 depreciation study and 2019 reserve adjustment in his testimony and his Attachment REW-2. Total adjustments to the proposed CGSA Direct per book reserves equal $4,778,322. Ms. Mindy Edwards explains and sponsors adjustments made to TGS Division and ONE Gas Corporate 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 $555,678,548. This is the sum of the adjusted test year balances for Plant in Service of $657,555,686 plus CCNC of $80,305,627 less Reserves of $(182,182,765).

Q. IS ALL OF THE COMPANY'S ADJUSTED PLANT IN SERVICE INCLUDED IN THIS STATEMENT OF INTENT USED AND USEFUL IN PROVIDING SERVICE?

A. Yes, all plant in service included in this Statement of Intent is used and useful in providing service as supported by my testimony and that of Ms. Mindy Edwards, Ms. Allison Edwards, Ms. McTaggart and Ms. Norman.

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;
- Amounts deferred in accordance with Commission Rule 8.209;
- Pension and Other Post Employment Benefits ("OPEB") Regulatory Asset;
- Prepaid Pension Asset; and
- Cash Working Capital ("CWC").

Q. REFERRING TO SCHEDULE B, 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 CGSA Direct Materials and Supplies Inventory and Stores

Load. Consistent with: standard ratemaking practices; the methodology applied by the Company in GUD Nos. 10488, 10506, 10526, 10656, 10739 and 10766; and past Commission decisions,[3] a thirteen-month average was used and results in a $4,272,141 balance to be included in rate base.[4]

Q. WHY IS IT APPROPRIATE TO INCLUDE "STORES LOAD" AS PART OF THE "MATERIALS AND SUPPLIES INVENTORY" BALANCES INCORPORATED INTO RATE BASE?

A. Overhead costs associated with materials management are accumulated in the Stores Load clearing account. When inventory dollars and Direct purchases are charged to expense accounts or to work orders, a portion of this accumulated materials management cost is charged to the same accounts. This additional cost relating to materials management overhead is referred to as "Stores Load." Because a portion of the Stores Load clearing account relates to the balance in the inventory account, it is appropriate to include an average of these amounts in rate base consistent with the inclusion of the average inventory balance.

Q. WHAT AMOUNTS HAVE BEEN DEFERRED AND REFLECTED WITHIN RATE BASE IN ACCORDANCE WITH COMMISSION RULE 8.209?

A. Schedule B, line 7, reflects the Company's deferred expenses associated with its Distribution Integrity Management Program ("DIMP") as of June 30, 2019. These amounts have been deferred in accordance with Commission Rule 8.209. Rule

[3] 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 *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).

[4] Please see Schedule B-1 for additional detail.

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 CGSA is $528,827[5] and includes monthly deferred DIMP expenses for the proposed CGSA from January 2019 through June 2019. Ms. Norman addresses the Company's DIMP-related activities in her direct testimony.

Q. HAVE THE COMPANY'S REGULATORS PREVIOUSLY AUTHORIZED TGS TO RECOVER DEFERRED AMOUNTS RELATED TO COMMISSION RULE 8.209?

A. Yes, the Commission has previously authorized TGS to recover deferred amounts related to Rule 8.209 in multiple proceedings.[6] In addition, the proposed CGSA

[5] Please see Schedule B-3 for additional detail.
[6] 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; and GUD No. 10766, Final Order.

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.[7]

Q. DID TGS FOLLOW THE SAME METHODOLOGY FOR CALCULATING THE DEFERRED AMOUNTS ASSOCIATED WITH COMMISSION RULE 8.209 IN THIS STATEMENT OF INTENT AS IT HAS IN PRIOR FILINGS?

A. Yes, the Company has followed the same methodology.

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

A. The Company has included $1,704,879 for a Pension and OPEB regulatory asset.[8] Texas Utilities Code §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, in the GCSA and CTSA (GUD No. 10488 and GUD No. 10526, respectively), the

[7] In 2017, 2018 and 2019, the cities in the GCSA approved the recovery of Rule 8.209 amounts in the Company's Cost of Service Adjustment (COSA) filings.
[8] Please see Schedule B-4 for additional detail.

Commission approved regulatory assets consistent with the statute, and ordered them to be amortized over six years. At the time the proposed rates go into effect, $707,384 will remain unamortized from the regulatory assets in those two cases. 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 June 30, 2019, those deferrals total to $997,496. The sum of these two equals the amount 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 $23,340,745. This asset is included on Schedule B, line 9. Company witness Cyndi King addresses the prepaid pension asset in her direct testimony.

Q. WHAT IS CASH WORKING CAPITAL?

A. CWC is the cash flow required to finance the day-to-day operations of a business. Because business operations both generate and expend cash, CWC can be a net inflow or a net outflow to a company. Company witness Timothy S. Lyons calculated the CWC amount of a negative $4,999,624 as shown on Schedule B, line 10 and supports the reasonableness of his calculation in his testimony.

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 11 and 12 are the balances at the test year end for customer deposits and customer advances, respectively. In addition, the Accumulated Deferred Income Taxes ("ADIT") balance shown on line 13 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. These funds are also deducted from the rate base calculation. Company witness Janet M. Simpson explains and sponsors the ADIT balance in her testimony.

Q. PLEASE EXPLAIN THE AMOUNTS SHOWN ON SCHEDULE B FOR THE BALANCES OF CUSTOMER DEPOSITS, CUSTOMER ADVANCES, AND ADIT.

A. The amounts reflected in Rate Base on Schedule B are equal to the proposed CGSA per book balances of customer deposits and customer advances as of June 30, 2019, adjusted for certain known and measurable changes as of September 30, 2019. Customer Deposits (line 11) are $(7,853,752). Customer Advances (line 12) are $(21,363,984). The ADIT balance (line 13) is $(80,421,556). These balances are treated for ratemaking purposes as offsets to the Company's invested capital or rate base.[9]

[9] For additional support for customer deposits, customer advances and ADIT, please see Schedule B-7, Schedule B-8 and Schedule B-9, respectively.

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 $473,468,036. This total amount includes all the component parts described above. Ms. Mindy Edwards' testimony provides details for Corporate and Division rate base items.

IV. FEDERAL INCOME TAX

Q. PLEASE EXPLAIN THE CALCULATION OF FEDERAL INCOME TAX EXPENSE AS SHOWN ON SCHEDULE F.

A. Federal income tax expense is computed on Schedule F using the method outlined in the Commission's Natural Gas Rate Review Handbook.[10] This method calculates federal income tax expense by recognizing that the equity component of a total required return is comparable to after-tax net income, as reflected on the financial statements. This method first derives after-tax net income by subtracting the interest expense on the long-term debt portion of return, from the total required return. Because the resulting after-tax net income amount is, by definition, the amount that should result after the deduction of income taxes, it is necessary to "gross it up" by multiplying by a factor of 1/(1-tax rate). The resulting calculated before-tax net income number is then multiplied by the federal income tax rate to derive federal income tax expense.

Before grossing up the "after tax income," however, it is necessary to eliminate the effect of items that represent Direct credits to federal income taxes and to eliminate the effect of items that may be appropriate for ratemaking purposes

[10] Commission Rate Review Handbook at 38-39 (Sept. 2017).

but are not allowable deductions on the Company's income tax return. The Company made an adjustment to the after tax income for the parking expense that is no longer tax deductible under the Tax Cuts and Jobs Act of 2017 (the "Act"). 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 Act, which lowered the federal corporate tax rate from 35% to 21%. Ms. McTaggart, Ms. Simpson and Company witness Jeffrey J. Husen discuss issues related to the Act in their direct testimonies. The adjusted test year federal income tax expense included in the Company's revenue requirement is $7,855,526.

Q. PLEASE DESCRIBE THE CHANGE TO THE DEDUCTIBILITY OF PARKING EXPENSES UNDER THE ACT.

A. As provided in IRS Notice 2018-99,[11] the Act added Code Section 274(a)(4) precluding employers from deducting, for tax purposes, qualified transportation fringe benefits paid or incurred after December 31, 2017. Qualified transportation fringe benefits include van pools, transit passes, bicycle commuting and qualified parking. The test year expense attributable to the proposed CGSA associated with these transportation costs is $140,742. This amount has been adjusted within the federal tax calculation on Schedule F-FIT, adding approximately $38,000 to the revenue requirement.

[11] https://www.irs.gov/pub/irs-drop/n-18-99.pdf.

Q. ARE THE 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 CGSA?

A. Yes. These adjustments to the historical test year amounts are appropriate and necessary to properly determine the Company's reasonable and necessary costs to provide service to TGS's proposed CGSA customers, which are appropriately recovered through base rates.

Q. HAS THE COMPANY CALCULATED THESE 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.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF GRACIE GUERRA

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

1. "My name is Gracie Guerra. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Rate Analyst II 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.

Gracie Guerra
Gracie Guerra

SUBSCRIBED AND SWORN TO BEFORE ME by the said Gracie Guerra on this 25th day of November, 2019.

MARY L PENA
NOTARY PUBLIC
ID# 11652311
State of Texas
Comm. Exp. 05-13-2023

Mary L. Peña
Notary Public in and for the State of Texas

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

MINDY R. EDWARDS

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF MINDY R. EDWARDS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mindy R. Edwards, and my business address is 15 East Fifth 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 a Rates Analyst. I am testifying on behalf of Texas Gas Service Company ("TGS" or the "Company"), which is a Division of ONE Gas.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Accounting with a minor in Economics from Oklahoma State University in 2013, and I am a licensed Certified Public Accountant in Oklahoma. I began my employment with ONE Gas on September 29, 2014 as an Accountant in the Financial Reporting Department. In February 2016, I began working in the Corporate Accounting Department while simultaneously fulfilling my duties in the Financial Reporting Department until July 2017. I began serving in my current position as a Rates Analyst in the Rates and Regulatory Department in August 2018. Prior to my employment at ONE Gas, I worked as an Audit Associate at BKD, LLP. from January to September 2014.

Q. PLEASE DISCUSS YOUR DUTIES AND RESPONSIBILITIES AS A RATES ANALYST.

A. My responsibilities include assisting the Divisions of ONE Gas, including TGS, with the review and analysis of company financial data and records and preparation of and participation in rate cases and other regulatory filings and related activities.

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

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I support the reasonableness of certain rate base adjustments, including Corporate and Division capital investments and prepayments. I also support Corporate depreciation and amortization expense allocated to the proposed Central-Gulf Service Area ("CGSA"), which is a combination of the existing Central Texas and Gulf Coast Service Areas (CTSA and GCSA, respectively) and the City of Beaumont, Texas.

Q. HOW DOES YOUR TESTIMONY RELATE TO OTHER COMPANY WITNESSES IN THE CASE?

A. My testimony relates to Company witness Gracie Guerra as she supports the proposed CGSA Direct service area rate base adjustments whereas, I support allocated Corporate and TGS Division rate base adjustments and depreciation expense. Company witness Marie J. Michels supports the proposed CGSA Direct service area expense adjustments, and Company witnesses Anthony Brown and Allison N. Edwards address allocated expense adjustments.

Q. WHAT SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring or co-sponsoring the following schedules:

RATE BASE:	
Schedule B (Rate Base)	Co-Sponsor with Ms. Guerra
Schedule B-2 (Prepays)	Sponsoring
Schedule C (Plant)	Co-Sponsor with Ms. Guerra and Ms. Allison Edwards
Schedule C-1 (CCNC)	Co-Sponsor with Ms. Guerra
Schedule D (Reserves)	Co-Sponsor with Ms. Guerra
OPERATING INCOME:	
Schedule G-15 (Depr Amort)	Co-Sponsor with Ms. Michels

The schedules I address in my testimony are for the Company's proposed CGSA. In addition to schedules that reflect the Company's requested consolidation for the CGSA, TGS is also providing stand-alone schedules for the CTSA and GCSA. The cost of service for customers in the City of Beaumont, Texas is included in and a part of the GCSA.

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes, I am sponsoring the exhibit listed under the table of contents.

Q. ARE ANY OF THE COSTS THAT YOU SPONSOR ALLOCATED FROM ONE GAS OR THE TGS DIVISION?

A. Yes. I support the Corporate and TGS Division capital investments, prepayments, and depreciation expenses relating to centralized services provided to ONE Gas' Operating Divisions or TGS service areas, including the proposed CGSA. These centralized services are provided more efficiently at the Corporate or Division level and are considered "Shared Services" costs. Mr. Brown discusses in his testimony the cost allocation methodology and supports the percentages used to allocate these costs to the proposed CGSA.

II. <u>RATE BASE ADJUSTMENTS</u>

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. 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. Ms. Guerra further discusses in her testimony Direct rate base and its three components.

Q. WHY IS IT NECESSARY TO INCLUDE CORPORATE AND TGS DIVISION INVESTMENTS IN RATE BASE?

A. Corporate and TGS Division investment assets are necessary to the provision of utility service to TGS and the proposed CGSA but are not reflected in the proposed CGSA Direct costs; thus, an adjustment is necessary to include these investments in rate base to determine the revenue requirement. This is the same approach TGS has taken in prior statements of intent, which the Commission has previously approved in: Gas Utilities Docket ("GUD") Nos. 9770, 9988; TGS's last fully litigated rate case GUD No. 10506; and TGS's settled cases GUD Nos. 10488, 10526, 10656, 10739 and 10766.[1]

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[1] *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 FoF 27 (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

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 CGSA. These rate base items include prepayments, net plant in service, 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 CGSA represent advances for items such as: annual equipment and software maintenance agreement fees; software license fees; insurance policy premiums for general liability; automobile and workers' compensation; and other miscellaneous prepaid items. ONE Gas and TGS Division prepayments are: provided on Schedule B-2 and Workpapers B-2.a.1 and B-2.b.1; included in rate base because they reflect an investment ONE Gas and

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at FoF 10 (Dec. 14, 2010); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the 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 (March 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); 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 at FoF 33 (Feb. 5, 2019).

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 Company witness Mark W. Smith, ONE Gas formed a wholly-owned captive insurance subsidiary, Utility Insurance Company ("UIC"), in 2017 to provide insurance to ONE Gas and its Divisions. Some UIC premiums are included in Corporate and TGS Division costs that are allocated to the proposed CGSA. A complete list containing UIC premiums included in rate base is attached to my testimony as Exhibit MRE-1. Company witness Stacey L. 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 third quarter of 2019.

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.[2]

Q. NEXT, PLEASE EXPLAIN THE ONE GAS AND TGS DIVISION CAPITAL INVESTMENT, ALLOCATED TO THE PROPOSED CGSA, SHOWN ON SCHEDULES C, C-1, AND D.

A. ONE Gas' net plant in service (gross plant less accumulated reserves), allocated from Corporate to TGS, is $40,234,170. The TGS Division net plant in service is $4,894,818. The proposed CGSA allocated share of these amounts is 46.4931%, or $20,981,866, based on the number of proposed CGSA customers relative to the total number of TGS customers. Mr. Brown discusses in his testimony the cost allocation methodology and supports the percentages used to allocate these investments to the proposed CGSA. Net plant in service 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 ONE GAS CAPITAL INVESTMENTS MADE DURING THE TEST YEAR AND REFLECTED ON SCHEDULES C AND C-1.

A. ONE Gas capital expenditures made during the test year and reflected on Schedules C and C-1 primarily consist of investments in computer software and equipment and leasehold improvements. Examples of those investments include:

- Replacement of existing routers, switches and wireless gear at company work locations that have currently met end of life or do not meet the ONE Gas standard to allow for proper support and manageability;

[2] 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; and GUD No. 10766, Final Order.

- Carbon Black Endpoint Detection and Response ("EDR") was implemented to allow ONE Gas to instantly disconnect ransomware or other malicious threats from the computer systems on the corporate and Supervisory Control and Data Acquisition network. EDR stops the spread of malware throughout the network, while also mapping out what malicious services, files and communications were created and communicating with a malicious Internet destination;

- Skype for Business was implemented to reduce the cost of telecommunication services across ONE Gas and its divisions by moving to Voice Over Internet Protocol technology instead of using analog lines;

- The Meter Management System upgrade will provide a method to track meters and meter devices using bar codes and bar code readers which will assist with the accuracy of meters and meter devices placed into inventory. The upgrade will also allow ONE Gas to run reports containing information about the meters and quality testing performed at the Meter Facility;

- Consolidation of the ONE Gas leak survey practice in order to deploy a new integrated technology solution to unify ONE Gas leak survey business functions from back-office planning to field survey completion. Integrated technology solutions include: (1) LocusSurvey as the mobile application used in the field; (2) Android mobile phones as the mobile device used in the field; (3) Necessary system integrations from the new mobile application to the ONE Gas existing enterprise applications; and (4) Compliance and operational reporting utilizing integrations between Maximo, Geographical Information Systems, LocusSurvey, and Power Business Intelligence ("BI");

- Utilization of predictive analytics to provide data science, data engineering, and architect resources to demonstrate that a Machine Learning model can accurately predict the cause of meter exceptions (e.g. misread, broken meter, safety issue, etc.), and reduce the total number of exceptions that must be manually processed each day;

- Web and mobile enhancements that focus on design and development activities for improving the customer experience while making online payments and preparatory work to enable search and self-management of website content. The primary goals of this project include system design and application development for website and guest payment features and optimization of storage and retrieval of website content to prepare for future search capabilities;

- Replacement of Data Center hardware with next generation units to ensure a secure, supportable and high-performing server infrastructure which will improve reliability and reduce downtime;

- Creation of a standardized rate change spreadsheet, rate comparison report, and an automatic rate update application in order to mitigate human error and incorrect customer billing. The intent of this project is to reduce the complexity of the rate updating process relied on by ONE Gas Customer Service business users, and to implement common processes and applications, where possible, across all distribution segments;

- LocusIQ implementation to document inspection activities and provide a statistical risk-based approach to managing the inspection program. This application is a cloud-based software with a mobile front-end; and

- Enhancements to existing Customer Relationship Management ("CRM") business processes to support Information Technology ("IT") and Pipeline Safety Compliance departments. The changes include: preparation for the implementation of Enterprise Architecture integration efforts and preparation for integration of BI with CRM. These enhancements will provide common processes and applications across all distribution segments, while also treating each implementation individually when necessary.

Q. WERE THESE PROJECTS AND RELATED CAPITAL EXPENDITURES PRUDENT, REASONABLE AND NECESSARILY INCURRED?

A. Yes, they were. IT provides critical services supporting all employees in their efforts to provide service safely and reliably to customers across ONE Gas' three states of operations, including the proposed CGSA. ONE Gas built these technology systems to provide the highest level of stability, reliability, and security. If a technology system becomes unavailable, operations may be impaired. Thus, it is necessary to provide reliable technology systems and infrastructure 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, and improve website functionality. 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 THE PLANT IN SERVICE, CCNC OR ACCUMULATED RESERVE ALLOCATED TO TGS?

A. Yes. Capital investment costs not related to the provision of utility services were removed. Costs for meals greater than $25 per person, exclusive of taxes and tip amount, and some hotel stays greater than $150 per night, exclusive of taxes, were removed, which Ms. Allison Edwards discusses in her testimony. The Company has also made five adjustments to include costs for the following: (1) to CCNC for the purchase of a building in Texas serving as a Customer Information Center; (2) to plant in service, CCNC and Accumulated Reserves for post-test year plant that was in service as of September 30, 2019; (3) to CCNC for the proposed CGSA's allocated portion of the Corporate balance of Construction Work in Progress ("CWIP") at September 30, 2019; (4) to plant in service, CCNC and Accumulated Reserves to reflect annualization of the cost allocation percentages as of third quarter 2019; and (5) to Accumulated Reserves in relation to Company witness Dr. Ronald E. White's 2019 depreciation study. These adjustments are reflected in Workpapers C.b, C.c, C-1.b, C-1.c, D.b, and D.c.

Q. PLEASE FURTHER EXPLAIN THE POST-TEST YEAR CORPORATE ADJUSTMENT TO PLANT IN SERVICE ON WORKPAPER C.C.1 AND TO CCNC ON WORKPAPER C-1.C.1.

A. The Company has included a post-test year adjustment to Plant in Service and CCNC for corporate capital investment placed into service after the test-year end through September 30, 2019.[3]

[3] As of September 30, 2019, post-test year plant has been placed in service and thus becoming used and useful in providing service to proposed CGSA customers.

Q. BRIEFLY DESCRIBE THE POST-TEST YEAR CORPORATE PLANT ADDITIONS INCLUDED AS AN ADJUSTMENT TO RATE BASE IN THIS FILING.

A. The ONE Gas capital expenditures included in the post-test year adjustment to Plant in Service and CCNC primarily consist of investments in computer software and equipment. Examples of those investments include:

- Replacement of laptop and desktop equipment that has exceeded warranty, thereby reducing unplanned repair expenses and providing a better end-user experience;
- Renewal of Microsoft Enterprise Agreement licenses, which are used on premise and allow Company users to connect remotely to a variety of application services;
- Replacements of modems that are at the end of their useful life and will no longer be supported by Verizon at the end of 2019;
- Enhancements to the Banner billing system to support better functionality for Web customers, process efficiencies for Customer Service Representatives' and Service Order standardization across ONE Gas' Divisions; and
- Maximo systems were upgraded to a more recent version. As part of the upgrade, the underlying Oracle database and Websphere were upgraded to newer versions, and servers were migrated from Windows-based to Linux.

Q. PLEASE FURTHER EXPLAIN THE CORPORATE CWIP ADJUSTMENT TO CCNC ON SCHEDULE C-1.C.1.

A. The Company included September 30, 2019 CWIP balances as an adjustment to CCNC. However, the Company is not ultimately requesting the inclusion of CWIP in its cost of service calculation. The Company will make a true-up adjustment to CCNC to exclude any plant that is not used and useful as of December 31, 2019, and will provide December 31, 2019 plant in service, CCNC, and Accumulated Reserve balances by February 14, 2020. ONE Gas' CWIP allocated from

Corporate to TGS is $5,250,217 and the proposed CGSA's allocated share is 46.4931%, or $2,440,989. Ms. Guerra discusses in her testimony the proposed CGSA Direct CWIP adjustment.

Q. WHY IS IT APPROPRIATE TO INCLUDE ALLOCATED CORPORATE CCNC BALANCES IN RATE BASE?

A. The proposed CGSA allocated portion of the Corporate CCNC balance is a part of used and useful plant both during the test year and for the known and measurable changes beyond the test year. As such, allocated CCNC is appropriately included in rate base, and this is consistent with the treatment approved in GUD Nos. 9988, 10217, 10488, and 10506.[4]

Q. PLEASE EXPLAIN THE TGS DIVISION ADJUSTMENT TO ACCUMULATED RESERVES ON WORKPAPER D.B.

A. The Company has made two adjustments to the Accumulated Reserve to account for the differences between the recorded reserve and computed reserve calculated in Dr. White's 2015 and 2019 Depreciation studies. The adjustment in relation to the 2015 Depreciation study transferred reserve dollars from all TGS Direct depreciable 390.2 accounts to TGS Division amortizable accounts, so there is enough reserve in the amortizable accounts for when those assets retire. As a result of Dr. White's 2019 Depreciation study, a similar issue was identified, and a similar, proforma adjustment has been made in this filing. Dr. White further discusses the 2019 Depreciation study and 2019 reserve adjustment in his

[4] GUD No. 9988, Final Order; *Statement of Intent of Texas Gas Service Company to Change Rates Within the Environs of the South Texas Service Area, GUD No. 10217*, Final Order (Mar. 26, 2013); GUD No. 10488, Final Order; and GUD No. 10506, Final Order.

testimony. Ms. Guerra explains and sponsors the adjustments made to Direct per book reserve balances.

III. OPERATING EXPENSE ADJUSTMENTS

Q. PLEASE EXPLAIN HOW THE DEPRECIATION AND AMORTIZATION EXPENSE ADJUSTMENT ON SCHEDULE G-15 IS CALCULATED.

A. Adjusted depreciation or amortization expense is calculated by multiplying proposed depreciation/amortization rates by depreciable plant in service. 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 and approved in TGS's last fully litigated rate case: GUD No. 10506, and TGS's settled cases; GUD Nos. 10488, 10526, 10656, 10739 and 10766.[5] Corporate depreciation rates and amortization periods are consistent throughout ONE Gas and its Divisions. The Kansas Corporation Commission[6] and Oklahoma Corporation Commission[7] 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

[5] 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; and GUD No. 10766, Final Order at FoF 37.

[6] *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).

[7] *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 20170079 (March 15, 2017).

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 2019 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.

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 six different Texas rate cases and are already being utilized in TGS statewide, including the Central Texas and Gulf Coast Service Areas. If the regulatory authority were to establish parameters for Corporate assets in the proposed CGSA 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 CGSA, which would be a complicated and costly process.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**CORPORATE UIC PREMIUMS ALLOCATED TO PROPOSED CGSA**														**Exhibit MRE-1**
2	**TEST YEAR ENDING 06/30/2019**														
3															
4	**LINE NO.**	**POLICY TYPE**	**JUNE[1]**	**JULY[1]**	**AUGUST[1]**	**SEPTEMBER[1]**	**OCTOBER[1]**	**NOVEMBER[1]**	**DECEMBER[1]**	**JANUARY[1]**	**FEBRUARY[1]**	**MARCH[1]**	**APRIL[1]**	**MAY[1]**	**JUNE[1]**
5	1	UIC Auto Liability	$ 896	$ 672	$ 448	$ 224	$ -	$ 935	$ 850	$ 765	$ 680	$ 595	$ 510	$ 425	$ 340
6	2	UIC Excess Liability	604,140	453,105	302,070	151,035	-	625,889	568,990	512,091	455,192	398,293	341,394	284,495	227,596
7	3	UIC Property	53,970	48,573	43,176	37,779	32,382	26,985	21,588	16,191	10,794	5,397	-	70,312	63,920
8	4	UIC Workers Compensation	42,200	31,650	21,100	10,550	-	36,564	33,240	29,916	26,592	23,268	19,944	16,620	13,296
9	5	**CORPORATE UIC PREMIUMS**	**$ 701,206**	**$ 534,000**	**$ 366,794**	**$ 199,588**	**$ 32,382**	**$ 690,373**	**$ 624,668**	**$ 558,963**	**$ 493,258**	**$ 427,553**	**$ 361,848**	**$ 371,852**	**$ 305,152**
10	6	TGS Distrigas Allocation %	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%
11	7	**CORPORATE UIC PREMIUMS ALLOCATED TO TGS**	**$ 175,372**	**$ 133,553**	**$ 91,735**	**$ 49,917**	**$ 8,099**	**$ 172,662**	**$ 156,229**	**$ 139,797**	**$ 123,364**	**$ 106,931**	**$ 90,498**	**$ 93,000**	**$ 76,319**
12	8	CGSA Allocation %	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%
13	9	**CORPORATE UIC PREMIUMS ALLOCATED TO CGSA**	**$ 81,536**	**$ 62,093**	**$ 42,651**	**$ 23,208**	**$ 3,765**	**$ 80,276**	**$ 72,636**	**$ 64,996**	**$ 57,356**	**$ 49,716**	**$ 42,075**	**$ 43,239**	**$ 35,483**
14															
15		**Footnotes:**													
16		[1] The UIC premium amounts contained in this exhibit are included in the 13 month avergage, calculated in "WKP B-2.b.1_Prepayments - ONE GAS Corp Prepayments Detail (CONFIDENTIAL)". Filter on "UIC" in the "Line Description" column to identify the UIC premiums contained in "WKP B-2.b.1_Prepayments - ONE GAS Corp Prepayments Detail (CONFIDENTIAL)".													

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**TGS DIVISION UIC PREMIUMS ALLOCATED TO PROPOSED CGSA**														**Exhibit MRE-1**
2	**TEST YEAR ENDING 06/30/2019**														
3															
4	**LINE NO.**	**POLICY TYPE**	**JUNE[1]**	**JULY[1]**	**AUGUST[1]**	**SEPTEMBER[1]**	**OCTOBER[1]**	**NOVEMBER[1]**	**DECEMBER[1]**	**JANUARY[1]**	**FEBRUARY[1]**	**MARCH[1]**	**APRIL[1]**	**MAY[1]**	**JUNE[1]**
5	1	UIC Auto Liability	$ 544	$ 408	$ 272	$ 136	$ -	$ 2,596	$ 2,360	$ 2,124	$ 1,888	$ 1,652	$ 1,416	$ 1,180	$ 944
6	2	UIC Excess Liability	376,688	282,516	188,344	94,172	-	2,462,669	2,238,790	2,014,911	1,791,032	1,567,153	1,343,274	1,119,395	895,516
7	3	UIC Property	324,560	292,104	259,648	227,192	194,736	162,280	129,824	97,368	64,912	32,456	-	428,340	389,400
8	4	UIC Workers Compensation	70,080	52,560	35,040	17,520	-	39,578	35,980	32,382	28,784	25,186	21,588	17,990	14,392
9	5	**TGS DIVISION UIC PREMIUMS**	**$ 771,872**	**$ 627,588**	**$ 483,304**	**$ 339,020**	**$ 194,736**	**$ 2,667,123**	**$ 2,406,954**	**$ 2,146,785**	**$ 1,886,616**	**$ 1,626,447**	**$ 1,366,278**	**$ 1,566,905**	**$ 1,300,252**
10	6	CGSA Allocation %	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%
11	7	**TGS DIVISION UIC PREMIUMS ALLOCATED TO CGSA**	**$ 358,867**	**$ 291,785**	**$ 224,703**	**$ 157,621**	**$ 90,539**	**$ 1,240,028**	**$ 1,119,068**	**$ 998,107**	**$ 877,146**	**$ 756,186**	**$ 635,225**	**$ 728,503**	**$ 604,527**
12															
13		**Footnotes:**													
14		[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)".													

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF MINDY EDWARDS

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

1. "My name is Mindy Edwards. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as a Rates Analyst I 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 this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Mindy Edwards

Mindy Edwards

SUBSCRIBED AND SWORN TO BEFORE ME by the said Mindy Edwards on this 6th day of December, 2019

Tami Hardway

Notary Public in and for the State of Oklahoma

Notary Public
State of Oklahoma
TAMI HARDWAY
TULSA COUNTY
COMMISSION #16001227
Comm. Exp. 2-5-20

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

MARIE J. MICHELS

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF MARIE J. MICHELS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Marie J. Michels, and my business address is 1301 South MoPac Expressway, Suite 400, Austin, Texas 78746.

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

A. I am a Manager of Rates and Regulatory Analysis for Texas Gas Service Company ("TGS" or the "Company"), which is a Division of ONE Gas, Inc. ("ONE Gas"). My responsibilities include preparing rate schedules, filings, and analyses for various jurisdictions and rate classes.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Accounting degree in 2005 and a Masters of Business Administration degree in 2010 from Texas State University. I have been employed at the Company for 14 years in various accounting and financial analysis roles. My responsibilities included the preparation and analysis of monthly financial statements, annual financial plans and forecasts, as well as the preparation of the Railroad Commission of Texas ("Commission") Annual Report on behalf of the Company.

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

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I describe the portion of the Company's requested operating expenses related to Direct expenses. As part of my testimony addressing operating expenses, I also explain adjustments the Company made to test year expenses to calculate its cost of service.

Q. HOW DOES YOUR TESTIMONY RELATE TO OTHER COMPANY WITNESSES IN THE CASE?

A. Along with my testimony addressing Direct costs, other Company witnesses address allocated amounts. Specifically, Company witness Mindy R. Edwards supports TGS Division and Corporate rate base adjustments and depreciation expense, while Company witness Anthony Brown supports Shared Services and Distrigas expense adjustments.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. I am sponsoring or co-sponsoring the following schedules:

OPERATING INCOME:	
Schedule G (Summary of Operating Revenue & Expense Adj)	Co-Sponsor with Mr. Brown
Schedule G-7 (Pension OPEB)	Sponsoring
Schedule G-9 (Miscellaneous Adjustments)	Co-Sponsor with Mr. Brown & Ms. Allison Edwards
Schedule G-10 (Rents)	Co-Sponsor with Mr. Brown
Schedule G-11 (Interest on Customer Deposits)	Sponsoring
Schedule G-12 (Uncollectible Expense)	Sponsoring
Schedule G-14 (Advertising Expense)	Co-Sponsoring with Mr. Brown
Schedule G-15 (Depreciation & Amortization)	Co-Sponsor with Ms. Mindy Edwards
Schedule G-16 (Ad Valorem Tax Expense)	Sponsoring
Schedule G-17 (Texas Franchise Tax Expense)	Sponsoring
Schedule G-18 (Stores Load)	Sponsoring
Schedule G-20 (Regulatory Expense)	Sponsoring
Schedule G-19 (TWE Load)	Sponsoring
Schedule G-24 (PIT)	Sponsoring
Schedule G-25 (Hurricane Harvey)	Sponsoring

The schedules that I address in my testimony are for the Company's proposed Central-Gulf Service Area ("CGSA"), which is a combination of the existing Central Texas and Gulf Coast Service Areas ("CTSA" and "GCSA") and the City of Beaumont, Texas. In addition to schedules that reflect the Company's requested consolidation for the CGSA, TGS is also providing stand-alone schedules for the CTSA and GCSA. The cost of service for customers in the City of Beaumont, Texas is included in and part of the GCSA.

II. <u>OPERATING REVENUE AND EXPENSES</u>

Q. PLEASE DESCRIBE SCHEDULE G.

A. Schedule G presents a summary of all revenues and expenses, including ONE Gas Pipeline Company ("OPC"), 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-25. Pages 2 and 3 reflect the same information as Page 1, organized by Federal Energy Regulatory Commission account number. The total amounts on page 1, line 25 of Schedule G equal the total operating amounts shown on page 3, line 101 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 Janet L. Buchanan. The expense adjustments detailed on Schedules G-4 through G-25 are discussed in the remainder of my testimony or in the testimony of Company witnesses Stacey R. Borgstadt and Mr. Brown.

OPC expenses are included in the Company's requested operating expenses because OPC will transfer the assets to TGS after a final order is issued in this case and the asset will become part of the TGS system in the proposed CGSA, as described by Company witnesses Shantel Norman and Stacey L. McTaggart.

Q. HOW WAS THE AMOUNT OF THE OPERATIONS AND MAINTENANCE ("O&M") ADJUSTMENT RELATED TO OPC DETERMINED?

A. Prior to ONE Gas' acquisition of ONEOK Transmission Company ("OTC"), TGS operated and maintained the pipeline for ONEOK. TGS billed or invoiced OTC monthly for the O&M expenses TGS incurred to operate and maintain the pipeline, and OTC reimbursed TGS for the O&M expenses. After the acquisition, TGS continued its operation and maintenance of the pipeline, now named OPC. The post-test year adjustment to reflect necessary O&M costs that TGS will incur when the pipeline becomes part of TGS's system is based on TGS's historical experience with actual O&M costs for the OPC line and excluding the historical reimbursement. Those historical O&M costs can be found on WKP G.a.2 column b; the exclusion of the reimbursement can be found on Schedule G-9.

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 CGSA, the Company incurs "allocable" expenses for Shared Services provided to customers in the proposed CGSA from various TGS and ONE Gas departments. A portion of these reasonable and necessary expenses must be allocated to the proposed CGSA to determine the total cost TGS incurs to provide service to proposed CGSA customers. For example, during the test year, personnel from various departments provided management, accounting, human resources, customer service and engineering services to the proposed CGSA and generated a variety of expenses that are directly charged or causally allocated to the proposed CGSA. Lastly, there are ONE Gas Corporate level costs allocated through Distrigas for necessary business functions such as treasury, investor relations and executive management that support operations in the proposed CGSA. The proposed CGSA's portion of test year costs charged to the allocable cost centers described above are included in the proposed CGSA's per book costs on Schedule G, column (a). The Company's allocation methodologies are discussed by Mr. Brown.

Q. DESCRIBE THE PENSION AND OTHER POST-EMPLOYMENT BENEFITS AMORTIZATION AMOUNT SHOWN ON SCHEDULE G-7.

A. Schedule G-7 shows the proforma annual amortization of the Pension and other post-employment employee benefits ("OPEB") Regulatory Asset included in rate base in accordance with Texas Utilities Code §104.059, as discussed in the direct testimony of Company witness Gracie Guerra. The amount includes amortization of: (1) the remaining portion of the pension and OPEB regulatory asset approved in Gas Utilities Docket ("GUD") No. 10526 that will not be fully amortized when proposed CGSA rates are implemented; and (2) the deferred annual Pension and OPEB expense that has occurred since GUD No. 10526 was filed. The proposed annual amortization period is based on a six-year time frame that would include five Gas Reliability Infrastructure Program ("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 the test-year actuals.

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, and legislative activities. Additionally, meals over $25 per person, exclusive of taxes and tip amount, some hotel stays over $150 per night, exclusive of taxes, and other miscellaneous adjustments were removed. Company witness Allison N. Edwards discusses the proposed adjustment for meal and hotel costs. Mr. Brown sponsors the adjustments related to Shared Services, which are directly assigned or causally allocated costs, and Distrigas, which are allocated indirect costs.

Q. DID THE COMPANY ADJUST FOR DUPLICATE SALES TAX?

A. Yes. Test year expenses on WKP G-9.a were adjusted to remove duplicate sales tax entries inadvertently made by the Company's Vertex tax software. Since the Company became aware that its software system inadvertently assessed tax on a small percentage of invoices for which sales tax was already included, the Company has provided employees with additional training to address this issue with those who routinely process invoices. Specifically, the Company's accounts payable team has taken the following steps: (1) directed employees to be diligent in identifying tax on the invoice and proper tax coding, when applicable; (2) directed field locations to use labels for coding invoices and to specify the tax amount when applicable; (3) contacted vendors that do not clearly indicate tax amounts on their invoices and requesting identification of tax amounts on future invoices; and (4) continued to address the importance of this issue and discuss issues that require diligence for preventing errors. Additionally, the Company has upgraded the

Vertex software, which will mitigate the likelihood of duplicate sales tax being assessed in the future.

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR RENT EXPENSE SHOWN ON SCHEDULE G-10.

A. On Schedule G-10, the Company adjusts its test year expense for rent to reflect known and measurable changes in rent expense. Mr. Brown sponsors the adjustments related to Shared Services and Distrigas. There are no adjustments for Direct costs.

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR INTEREST ON CUSTOMER DEPOSITS SHOWN ON SCHEDULE G-11.

A. The proposed CGSA interest on customer deposits has been adjusted and calculated by applying the current Commission-required interest rate of 1.92%[1] to the adjusted balance of proposed CGSA customer deposits as shown on Schedule B-7 and as discussed in Ms. Guerra's testimony. The difference between this amount and test year interest on customer deposits expense 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 CGSA adjusted base revenues and other revenues. This adjusted expense level is calculated by multiplying the adjusted base revenues and other revenues by the three-year average of non-gas-cost-related Direct write-offs for the

[1] Railroad Commission of Texas, Bulletin No. 1118, Sec. 6(1)(B), October 31, 2019 (citing to Historical PUC Interest Rates, https://www.puc.texas.gov/industry/electric/reports/HRates/HistRates.pdf).

proposed CGSA divided by total proposed CGSA 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, and 10656, as well as other gas utilities in Texas.[2] 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 CGSA incorporated areas.

Q. PLEASE DESCRIBE THE CALCULATIONS ASSOCIATED WITH ADVERTISING EXPENSE ON SCHEDULE G-14.

A. Commission Rule 7.5414 states that actual expenditures for advertising will be allowed as a cost of service item for rate-making purposes provided that the total sum of such expenditures shall not exceed one-half of 1% of the gross receipts of the utility for utility services rendered to the public. Schedule G-14 demonstrates that total adjusted advertising expense included in the proposed revenue requirement is $37,109 and is less than the allowable amount of $988,823.

[2] *See e.g., Statement of Intent filed by Atmos Energy Corp., to Increase Gas Utility Rates Within the Unincorporated Areas Served by the Atmos Energy Corp., Mid-Tex Division*, GUD No. 10170, 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).

Ms. McTaggart addresses the disallowed expenses of civic and charitable expenses and membership dues in her testimony.

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, 2018 Distribution Integrity Management Program deferral balance, pursuant to Commission Rule 8.209, is included and is calculated using the proposed CGSA depreciation rates for mains and services. The proposed CGSA Direct plant depreciation rates were developed in the 2019 depreciation study conducted by Company witness Dr. Ronald E. White, who describes the depreciation study and the resulting rates in his direct testimony.[3] 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 CGSA 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.

[3] The 2019 study was based on asset balances at December 31, 2018. The plant balances in the study will not exactly match the Company's calculated rate base in its cost of service, which was based on a test year ended June 30, 2019 updated for known and measurable changes through September 30, 2019.

In addition to depreciation expense associated with the proposed CGSA plant in service, Schedule G-15 includes depreciation expense associated with the OPC acquisition, and the allocated Corporate and TGS Division office plant. Test year depreciation expense for OPC was calculated primarily based on the rates recommended by Dr. White for the Company's other assets in those same accounts. Because TGS did not own OPC at the time of the 2019 depreciation study, the specific OPC assets were not included in the study. However, the 2019 depreciation study provides more current rates for the types of asset utilized by OPC; therefore, the Company has adopted the 2019 depreciation study life parameters for those accounts for purposes of calculating depreciation rates for OPC assets. For those OPC asset accounts that were not addressed in the 2019 depreciation study, the Company has retained existing rates. In the event that the Commission does not adopt the proposed rates, the Company proposes to use the existing rates for the OPC assets. Exhibit MJM-1 provides the existing depreciation rates for OPC assets which are based on the depreciation rates of the asset at the time of purchase from ONEOK. The OPC existing depreciation rates provided on Exhibit MJM-1 were also provided in response to discovery issued in GUD No. 10877.

Ms. Mindy Edwards co-sponsors Schedule G-15 and supports the depreciation expense related to the TGS Division and Corporate Plant. TGS will update depreciation expense when it updates plant in service, construction completed not classified and reserves to December 31, 2019 balances by February 14, 2020.

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, 2018. Net plant in service as of January 1, 2018 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 federal income tax accrual on the Company's books and is excluded from the per book test year numbers for the proposed CGSA to calculate separate stand-alone proposed CGSA federal income tax and Texas franchise tax amounts in this filing. Schedule G-17 shows the adjustment to calculate the proposed CGSA stand-alone Texas franchise tax amount by multiplying TGS's franchise tax rate (for the 2018 return due in 2019) by the proposed CGSA'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 CGSA 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 CGSA stores costs that were under-cleared relative to the proposed CGSA costs incurred during the test year. TGS accounts for stores costs through a clearing account. Costs are accumulated in the stores load clearing account on the balance sheet and then cleared to capital and expense accounts based on a percentage load applied to all requisitions for materials and supplies. Because the percentage load is based on estimated usage and costs, the amount cleared may be more or less than the costs incurred during any given twelve-month period. During the test year, the amounts cleared from the proposed CGSA stores clearing account were less than the proposed CGSA 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 CGSA stores clearing account during the test year. As shown on lines 4 through 7, adjustments were made to reflect the difference between proposed CGSA 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. This amount has been multiplied by the percentage of stores load charged to expense accounts in the proposed CGSA during the test year to determine the adjustment to test year expense and the distribution of that adjustment to specific applicable expense accounts as shown on Schedule G-18, lines 12 through 23.

Q. PLEASE EXPLAIN THE LOAD CLEARING ADJUSTMENT FOR TWE 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 CGSA TWE during the test year were less than the proposed CGSA actual costs incurred. 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-19, lines 1 through 3. Lines 4 through 9 reflect any necessary adjustments relating to the dollars that were charged into the proposed CGSA TWE clearing account during the year. The primary costs associated with TWE are depreciation, gasoline and maintenance and repair costs. No adjustment was made to the test year level of gasoline or maintenance and repair costs. However, depreciation expense associated with vehicles and major work equipment is also charged to the TWE clearing cost. Line 4 reflects an adjustment to increase 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 an increase to test year proposed CGSA TWE clearing amounts and is shown on line 10. This amount has been multiplied by the percentage of TWE load charged to expense accounts in the proposed CGSA during the test year to determine the adjustment to test year expense and the distribution of that adjustment to specific applicable expense accounts as shown on Schedule G-19, lines 14 through 35.

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR REGULATORY EXPENSE REFLECTED ON SCHEDULE G-20.

A. Schedule G-20 reflects the adjusted regulatory expenses for the test year. In GUD No. 10526, the Commission approved the recovery of a regulatory asset of $280,196.80 representing regulatory expenses incurred as part of prior GRIP and other regulatory proceedings, with a six year amortization period and an annual amortization expense of $46,699. As of June 2019, the remaining balance was $155,665. The Company is requesting that the remaining balance of this previously approved regulatory asset be recovered over a six-year period in base rates, and 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.

For the recovery of rate case expenses associated with the filing of the instant case, the Company requests recovery through a separate rider as described in the testimony of Ms. McTaggart.

Q. PLEASE EXPLAIN THE PIT ADJUSTMENT REFLECTED ON SCHEDULE G-24.

A. Schedule G-24 reflects the pipeline integrity testing expense to include in base rates if the Company's request for a rider is not approved.

As explained in the direct testimony of Ms. McTaggart, the Company is requesting to recover certain pipeline integrity testing costs incurred during the test year and going forward through a rider. Ms. Norman explains and supports the reasonableness and necessity of the pipeline integrity testing costs, and Ms. McTaggart addresses the appropriateness of recovering the pipeline integrity testing expense through a rider. If the rider is approved, the adjustment shown on Schedule G-24 should be removed from the Company's base revenue requirement.

Q. PLEASE EXPLAIN THE HURRICANE HARVEY ADJUSTMENT REFLECTED ON SCHEDULE G-25.

A. Schedule G-25 reflects the expense related to Hurricane Harvey, net of insurance reimbursement, to include in rate base if the Company's request for a rider is not approved. Ms. McTaggart addresses recovering the Hurricane Harvey expense through a rider. If the rider is approved, the adjustment shown on Schedule G-25 should be removed from the Company's base revenue requirement.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Depreciation Expense Summary

ONEOK

049 Oneok Transmission Co — **Financial** — **Month: Jun/2019**

Depreciation Group	Ending Plant Balance	Depreciation Base	Depreciation Rate	Calculated Expense	Depreciation Adjustment	Other Reserve Transaction	COR Activity	End Reserve
Depreciable								
General Plant								
049 391.1 - Office Furniture & Fixt	$14,671.41	$14,671.41	4.3200%	$0.00	$0.00	$0.00	$0.00	$14,671.41
049 392.2 - Pickup Trucks & Vans	$0.00	$0.00	8.1400%	$0.00	$0.00	$0.00	$0.00	$0.00
049 394.1 - Tools	$483.07	$483.07	5.9700%	$0.00	$0.00	$0.00	$0.00	$483.07
General Plant Total	15,154.48	$15,154.48		0.00	$0.00	$0.00	0.00	15,154.48
Transmission								
049 301.0 - Organization Costs	$1,307.02	$1,307.02	6.6700%	$7.26	$0.00	$0.00	$0.00	$726.00
049 303.0 - Intangible Property	$14,335.75	$14,335.75	0.0000%	$0.00	$0.00	$0.00	$0.00	$14,335.75
049 365.1 - Land	$89,636.82	$89,636.82	0.0000%	$0.00	$0.00	$0.00	$0.00	$0.00
049 365.2 - ARO	$0.00	$0.00	0.0000%	$0.00	$0.00	$0.00	$0.00	$0.00
049 365.2 - Rights of Way	$2,445.79	$2,445.79	1.3000%	$2.65	$0.00	$0.00	$0.00	$2,123.65
049 366.1 - Compressor Station Stru	$2,345.69	$2,345.69	4.0400%	$0.00	$0.00	$0.00	$0.00	$2,345.69
049 367.0 - Mains	$6,909,860.63	$6,909,860.63	1.8600%	$10,710.28	$9,448.00	$0.00	$0.00	$2,327,212.65
049 369.0 - Measuring & Regulating	$132,498.88	$132,498.88	3.0000%	$331.25	$0.00	$0.00	$0.00	$63,475.52
049 369.1 - ARO	$0.00	$0.00	0.0000%	$0.00	$0.00	$0.00	$0.00	$0.00
049 369.1 - Measuring Station Equip	$810,699.80	$810,699.80	2.6200%	$1,770.03	$0.00	$0.00	$0.00	$537,229.03
049 371.0 - Other Transmission Eq	$45,840.00	$45,840.00	2.6200%	$100.08	$0.00	$0.00	$0.00	$11,056.45
Transmission Total	8,008,970.38	$8,008,970.38		12,921.55	$9,448.00	$0.00	0.00	2,958,504.74
Depreciable Total	8,024,124.86	$8,024,124.86		$12,921.55	$9,448.00	$0.00	0.00	2,973,659.22
Company/Set of Books Total:	$8,024,124.86	$8,024,124.86		$12,921.55	$9,448.00	$0.00	0.00	$2,973,659.22

Note: This report is filtered.

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF MARIE MICHELS

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

1. "My name is Marie Michels. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Manager of the Rates and Regulatory Compliance Department of 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.

Marie Michels

SUBSCRIBED AND SWORN TO BEFORE ME by the said Marie Michels on this 25th day of November, 2019

MARY L PENA
NOTARY PUBLIC
ID# 11652311
State of Texas
Comm. Exp. 05-13-2023

Mary L. Pena
Notary Public in and for the State of Texas

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

ANTHONY BROWN

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF ANTHONY BROWN

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Anthony Brown, and my business address is 1301 South MoPac Expressway, Suite 400, Austin, Texas 78746.

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

A. I am employed by Texas Gas Service Company ("TGS" or the "Company") as a Rate Specialist, which is a Division of ONE Gas, Inc. ("ONE Gas").

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Business Administration with a major in Finance from Angelo State University in 2013 and Master's in Business Administration from Angelo State University in 2015. I began my career with TGS in September 2015 as a Rate Analyst I. In July 2019, I was promoted to Rate Specialist.

Q. PLEASE DISCUSS YOUR DUTIES AND RESPONSIBILITIES AS A RATE SPECIALIST.

A. My responsibilities include: the review and analysis of Company and ONE Gas financial data; preparation of and participation in rate cases and other regulatory filings; and related activities for TGS.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have filed testimony in Gas Utilities Docket ("GUD") Nos. 10739 and 10766 before the Railroad Commission of Texas ("Commission").

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, they were.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address Shared Services costs TGS is requesting to recover through rates for the proposed Central-Gulf Service Area ("CGSA"). Shared Services are functions or services provided by employees at the TGS Division or ONE Gas levels that are necessary for the provision of natural gas service. Shared Services costs can be assigned directly or allocated to a specific service area. Specifically, I: (1) provide an overview of ONE Gas' organizational structure, which includes Shared Services and Direct service areas; (2) explain and support ONE Gas' cost allocation methodology, including the ONE Gas Distrigas[1] formula ("Distrigas"); (3) explain and support the miscellaneous operating expense adjustments for Shared Services; (4) explain the rent and lease operating expense adjustments for Shared Services; (5) explain and support the injuries and damages

[1] Distrigas of Mass. Corp., Opinion No. 291, 41 FERC 61, 205 (1987).

adjustment; (6) explain the Distrigas allocation adjustment; and (7) identify the Shared Services causal allocation.

Q. HOW DOES YOUR TESTIMONY RELATE TO OTHER COMPANY WITNESSES IN THE CASE?

A. My testimony relates to Company witness Marie J. Michels as she supports the proposed CGSA Direct service area expense adjustments whereas, I support adjustments for allocated expenses. Also, Company witness Mindy R. Edwards supports TGS Division and Corporate rate base adjustments and depreciation expense, using the cost allocation methodology and calculations that I support in my testimony.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes, I am sponsoring or co-sponsoring the following schedules:

OPERATING INCOME:	
Schedule G (Summary of Operating Revenue & Expense Adj)	Co-Sponsor with Ms. Michels
Schedule G-9 (Miscellaneous Adjustments)	Co-Sponsor with Ms. Michels and Ms. Allison Edwards
Schedule G-10 (Rents and Leases)	Co-Sponsor with Ms. Michels
Schedule G-13 (Inj & Dam)	Sponsoring
Schedule G-14 (Advertising)	Co-Sponsor with Ms. Michels
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 CGSA, which is a combination of the existing Central Texas and Gulf Coast Service Areas and the City of Beaumont, Texas. In addition to schedules that reflect the

Company's requested consolidation for the CGSA, TGS is also providing stand-alone schedules for the Central Texas and Gulf Coast Service Areas. In the stand-alone schedules, the cost of service for customers in the City of Beaumont, Texas is included in and a part of the Gulf Coast Service Area cost of service.

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

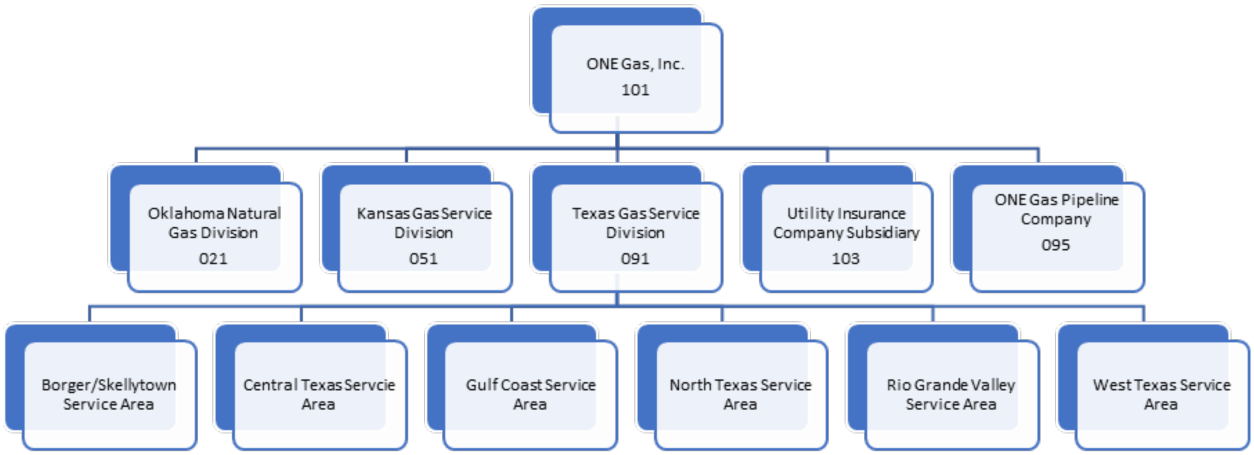
A. Yes, they were.

II. ORGANIZATIONAL STRUCTURE OVERVIEW

Q. HOW IS ONE GAS ORGANIZED?

A. As visually depicted in the chart below, ONE Gas has three divisions, Oklahoma Natural Gas, Kansas Gas Service, and TGS that serve more than 2.2 million customers. ONE Gas currently has two affiliate companies, Utility Insurance Company ("UIC"), a wholly-owned captive insurance subsidiary and ONE Gas Pipeline Company ("OPC"), which was formed following the recent acquisition of assets from ONEOK, Inc. Company witness Mark W. Smith describes UIC and the services it provides in his testimony. Company witnesses Shantel Norman and Stacey McTaggart provide testimony regarding OPC, the acquisition and related assets.[2]

[2] The OPC assets will be incorporated into TGS's existing system following this case.



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 SHARED SERVICES IN THE REQUESTED 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

CGSA by TGS Division and ONE Gas employees, and the costs associated with those services are included in the requested revenue requirement.

Q. ARE THE UIC PREMIUMS FOR ONE GAS AND TGS INCLUDED IN THE COMPANY'S REQUESTED REVENUE REQUIREMENT?

A. Yes, they are. UIC premiums to ONE Gas and TGS are included as allocated costs to the proposed CGSA. A complete list containing the UIC premiums included in operations and maintenance ("O&M") expense allocated to the proposed CGSA is attached to my testimony as Exhibit AQB-1. Ms. Mindy Edwards provides the UIC costs included in rate base allocated to the proposed CGSA. Mr. Smith provides testimony describing UIC and its services, and Ms. McTaggart discusses the Company's compliance with the associated affiliate standard.

Q. ARE OPC COSTS ALLOCATED THROUGH THE COMPANY'S COST ALLOCATION METHODOLOGY?

A. No, they are not. All OPC costs are attributable directly to the proposed CGSA. Ms. Michels and Company witness Gracie Guerra provide testimony about OPC expenses and rate base, respectively.

III. COST ALLOCATION METHODOLOGY

Q. WHAT IS THE PURPOSE OF COST ALLOCATIONS?

A. The purpose of cost allocations is to determine and reasonably allocate each business entity's proportionate share of costs for certain support services it receives from TGS Division and ONE Gas. Because the costs to provide these services are "shared" by multiple business entities 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. To the extent that responsibility for costs can be specifically attributed to a business entity or service area, those costs are directly assigned. Conversely, indirect costs are costs that cannot be specifically attributed to a business entity or service area and thus 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 using a specific causal relationship, such as customer count, and would be considered shared costs, which are discussed further below. Any remaining indirect costs are allocated according to a formula that has been previously approved 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 at the service area level, TGS Division level, or Corporate level. Costs are directly assigned for services such as meter reading, leak surveys, field customer service, fleet expenses, certain information technology 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 AQB-2.

- Human Resources - Provides professional development and training programs for active employees.
- Information Technology - 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 CGSA WERE A STAND-ALONE BUSINESS ENTITY?

A. Yes, these services would need to be provided even if the proposed CGSA was a standalone entity. Having these services performed centrally is efficient and allows for economies of scale and for the costs of those services to be spread across the business entities 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 by the Federal Energy Regulatory Commission ("FERC") in a rate proceeding for a natural gas transmission company, Distrigas of Massachusetts Corporation.[3] The formula used by Distrigas of Massachusetts Corporation was a slight modification of the old Massachusetts formula (a three-part formula consisting of gross plant, gross revenues and labor) which, prior to the acceptance of the Distrigas method, was widely accepted by numerous regulatory agencies across the country. In its opinion, FERC accepted the Modified Distrigas method (a three-part formula consisting of gross plant, net revenues and labor) as a reasonable and acceptable methodology for allocating costs for ratemaking purposes.

[3] Distrigas of Mass. Corp., Opinion No. 291, 41 FERC 61, 205 (1987).

Q. PLEASE EXPLAIN HOW COSTS ARE ALLOCATED USING THE DISTRIGAS METHOD.

A. The Distrigas Method ensures that ONE Gas allocates Corporate costs to each business entity on a consistent basis 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.[4] These modifications further refine the Distrigas method to fairly and reasonably allocate the costs to the ONE Gas business entities, including TGS.

Q. HAS THE SAME COST ALLOCATION METHODOLOGY BEEN APPLIED IN PRIOR ONE GAS PROCEEDINGS?

A. Yes, it has. This methodology has been used since 1994 to allocate Corporate costs. It is important to ONE Gas to have a common allocation methodology approved by the regulatory agencies in the states in which it operates to ensure that the method is fair to each of the ONE Gas business entities and their customers. This methodology was applied in the Company's Gulf Coast Service Area in 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;

[4] Currently, the Company 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.

North Texas Service Area in GUD No. 10739; and the Borger-Skellytown Service Area in GUD No. 10766.

Additionally, the Oklahoma Corporation Commission ("OCC") has also approved the use of the cost allocation method used by ONE Gas in prior rate cases. Importantly, both the Commission[5] and the OCC[6] have approved ONE Gas' refinement of the Modified Distrigas allocation method. This methodology is also currently used in Kansas. The Kansas Corporation Commission ("KCC") accepted ONEOK's allocation methodology in a settled 2005 Kansas Gas Service rate case[7] and ONE Gas' allocation methodology in the 2016 Kansas Gas Service rate case.[8]

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 business entities on a consistent basis by applying the same cost-causation principles and methodologies. Furthermore, this methodology has been previously approved as a reasonable

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[5] *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 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).

[6] *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 at 113 of 134 (Oct. 4, 2005).

[7] *In the Matter of the Application of Kansas Gas Service, a Division of ONEOK, Inc., for Adjustments of Its Natural Gas Service in the State of Kansas,* Docket No. 06-KGSG-1209-RTS, Order Granting Joint Motion and Approving Stipulated Settlement Agreement (Nov. 16, 2006).

[8] *In the Matter of the Application of Kansas Gas Service, a Division of ONE Gas, Inc., for Adjustment of its Natural Gas Rates in the State of Kansas,* Docket No. 16-KGSG-491-RTS, Order Approving Unanimous Settlement Agreement (Nov. 29, 2016).

means of allocating Corporate costs by this Commission, the FERC, the KCC, and the OCC.

IV. OPERATING EXPENSE ADJUSTMENTS

Q. WHAT IS SHOWN ON WORKPAPER G.A.2.A?

A. The Shared Services per book amount, including Distrigas, that I am supporting totals $77,927,259, of which $36,230,798 is allocated to the proposed CGSA. Workpaper G.a.2.a provides a summary showing the TGS allocated test year amount along with an O&M expense factor calculation applied to the adjustments.

Q. DESCRIBE THE MISCELLANEOUS ADJUSTMENTS SHOWN ON SCHEDULE G-9.

A. Schedule G-9 contains miscellaneous adjustments to remove expenses not currently allowed for regulatory recovery such as civic activities, sponsorships, charitable contributions, and legislative activities. Additional adjustments include the removal of royalty fees, inclusion of certain telecommunication activity, and an adjustment to account for the known and measurable change in insurance costs.

Q. DESCRIBE THE RENT ADJUSTMENT SHOWN ON SCHEDULE G-10.

A. Schedule G-10 annualizes test year expense for rent, common area maintenance, and parking 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 July 2015 through June 2019 (4 years). Next, injuries and damages expense for the twelve months ended June 2019 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.[9] This is the same treatment the Company followed in GUD Nos. 10488, 10526, 10656, 10739, and 10766.[10]

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[9] GUD No. 9988, Final Order at FoF No. 26 (Dec. 14, 2010); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Area (EPSA), Permian Service Area (PSA), and Dell City Service Area (DCSA),* GUD No. 10506, consol., Final Order at FoF Nos. 92 and 93 (Sept. 27, 2016).

[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 (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 (March 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); 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).

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 third quarter of 2019 is also included on Schedule G-21. This adjustment is consistent with the methodology used in prior statements of intent and with prior Commission decisions.

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.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

CORPORATE UIC PREMIUMS ALLOCATED TO CGSA
TEST YEAR ENDING 6/30/2019

Line	Company	Policy Type	GL Test Year Amount[1]	Test Year Adjustment[1]	Corporate Adjusted Test Year	Pro Forma Distrigas % to TGS	Allocated Adjusted Test Year	Allocation % to CGSA	CGSA Adjusted Test Year	O&M Expense Factor	CGSA Adjusted Test Year (with O&M Factor applied)
1	101	UIC Property	66,751	9,950	76,701	25.01%	19,183	46.49%	8,919	88.69%	7,910
2	101	UIC Workers Compensation	61,674	(21,792)	39,882	25.01%	9,974	46.49%	4,637	88.69%	4,113
3	101	UIC Excess Liability	1,059,328	(376,544)	682,784	25.01%	170,764	46.49%	79,393	88.69%	70,414
4	101	UIC Auto Liability	1,576	(556)	1,020	25.01%	255	46.49%	119	88.69%	105
5	**Company 101 Total**		**$ 1,189,328**	**$ (388,942)**	**$ 800,386**		**$ 200,177**		**$ 93,068**		**$ 82,542**

[1] - The source of the "GL Test Year Amount" and the "Test Year Adjustment" in this exhibit is Workpaper G-9.B.3 Insurance Adjustment.

TGS DIVISION UIC PREMIUMS ALLOCATED TO CGSA
TEST YEAR ENDING 6/30/2019

Line	Company	Policy Type	GL Test Year Amount[1]	Test Year Adjustment[1]	TGS Division Adjusted Test Year	Allocation % to CGSA	CGSA Adjusted Test Year	O&M Expense Factor	CGSA Adjusted Test Year (with O&M Factor applied)
1	91	UIC Property	$ 402,443	$ 64,840	$ 467,283	46.49%	$ 217,254	88.69%	$ 192,683
2	91	UIC Excess Liability	2,167,722	518,828	2,686,550	46.49%	1,249,059	88.69%	1,107,791
3	91	UIC Workers Compensation	48,795	(5,625)	43,171	46.49%	20,071	88.69%	17,801
4	91	UIC Auto Liability	2,437	400	2,837	46.49%	1,319	88.69%	1,170
5	**Company 91 Total**		**$ 2,621,398**	**$ 578,443**	**$ 3,199,841**		**$ 1,487,704**		**$ 1,319,444**

[1] - The source of the "GL Test Year Amount" and the "Test Year Adjustment" in this exhibit is Workpaper G-9.B.3 Insurance Adjustment.

CORPORATE ALLOCATION MANUAL

Revised /December 1, 2019
Corporate Accounting Department

The Corporate Allocation Manual provides documentation for current practices used by ONE Gas, Inc. (ONE Gas) for allocation of corporate administrative costs to ONE Gas business entities. A business entity is defined as a division or subsidiary of ONE Gas. Corporate administrative costs that are incurred for the direct benefit of one specific business entity, known as direct costs, 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 provides a reasonable and justifiable method of cost assignment, so that each business entity receives its proportionate share of corporate administrative costs and prevents subsidization.

Proper classification of costs is the responsibility of each employee and his or her supervisor when preparing, approving, and processing any accounting document (invoices, amortizations, journal entries, etc.). The classification of costs includes assigning the appropriate account coding string as defined in our Classification of Accounts Manual (which includes codes for 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

The application of our fully distributed cost allocations occurs through a "three-step" allocation method. The first step begins with the premise that to the extent practical, direct costs specifically attributed to a business entity are charged directly to that business entity. In the second step, indirect costs that are significant in amount, but which cannot be charged directly are allocated to business entities on the basis of a 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 cannot be charged directly or associated with an identifiable causal relationship, are allocated to business entities using the ONE Gas's Modified Distrigas Allocation methodology (ONE Gas Distrigas).

ONE GAS Distrigas Methodology

The Distrigas Cost Allocation Methodology (Distrigas Method) was first approved by the Federal Energy Regulatory Commission (FERC) in a rate proceeding for a natural gas transmission company, Distrigas of Massachusetts, L.L.C. The Distrigas formula is a slight modification of the Massachusetts Allocation Method (a three part formula consisting of gross plant, gross revenues and payroll) which, prior to the acceptance of the Distrigas formula, was widely accepted by numerous regulatory agencies across the country as a just and reasonable method of allocating corporate overhead and other costs. In its preceding at the FERC, Distrigas of Massachusetts, L.L.C. argued that the Massachusetts formula was flawed in that the formula over-allocated costs to utilities due to its inclusion of the cost of fuel in gross revenues. This had the effect of inflating the allocation of costs to utility operations which benefitted non-utility operations. The FERC agreed and accepted the modified version of the formula, which is generally known as the Distrigas Method, as 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 and investments, 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 consolidated 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. Allocated 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 plans and processes related to technology solutions and 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 support of all of the company technology	1. Allocated through the OGS- Distrigas methodology.
Cell phones, local and long-distance telephone service, pagers and internet expenses	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. Labor and benefit costs are allocated based on an internally developed analysis. 2. Other costs 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.
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 the Sarbanes-Oxley compliance software and network security monitoring (cyber security)	Costs are allocated through the OGS-Distrigas methodology.
Pipeline Support Systems	Charged directly to the business entity receiving benefit of the service.

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.
Federal and state income tax, ad valorem, sales & use tax and franchise tax filings	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 using the causal relationship of employee headcount for each respective business entity. b. Vehicle: Allocated using the causal relationship of vehicle count for each respective business entity. c. Excess Liability: Allocated through the OGS-Distrigas methodology. d. Directors & Officers Liability: Allocated through the OGS-Distrigas. e. Property and Terrorism: Allocated using the causal relationship of property values for each respective business entity.

	f. 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.
Property Accounting - centralized accounting for the property, plant & equipment	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.
Billing Control - centralized 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. Costs are allocated to the business entities through the OGS-Distrigas methodology. 2. Charged directly to the business entity receiving benefits of the services provided in certain instances.
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 responsible for the cost incurred. 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.
ONE Gas rent and utilities	1. Charged directly to the business entities with operations in the corporate building based on square footage utilized. 2. Costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) or to ONE Gas are allocated to the business entities through the OGS-Distrigas methodology.
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 TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF ANTHONY BROWN

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

1. "My name is Anthony Brown. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Rates 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.

Anthony Brown

SUBSCRIBED AND SWORN TO BEFORE ME by the said Anthony Brown on this 25th day of November, 2019.

MARY L PENA
NOTARY PUBLIC
ID# 11652311
State of Texas
Comm. Exp. 05-13-2023

NOTARY PUBLIC STATE OF TEXAS

Mary L. Pena
Notary Public in and for the State of Texas

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

ALLISON N. EDWARDS

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF ALLISON N. EDWARDS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Allison N. Edwards, and my business address is 15 East Fifth 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 a Manager of Rates and Regulatory Analysis.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I am a licensed Certified Public Accountant with a Bachelor of Science degree in Finance and a Master of Science degree in Accounting and Financial Analysis. I began my employment with ONEOK, Inc. ("ONEOK") in November 2011 as a Rates Analyst I and retained that position with ONE Gas after its separation from ONEOK. In September 2015, I was promoted to a Rates Analyst II. In September 2016, I accepted a position as a Tax Analyst II in the Tax Accounting Department. I began serving in my current position as a Manager of Rates and Regulatory Analysis in April 2018. Prior to my employment at ONEOK, I worked as a Cost Analyst at BOK Financial ("BOKF") from June 2009 to November 2011. From September 2005 to June 2009, I worked as a Senior Banker at Bank of Oklahoma (a subsidiary of BOKF).

Q. PLEASE DISCUSS YOUR DUTIES AND RESPONSIBILITIES AS A MANAGER OF RATES AND REGULATORY ANALYSIS.

A. My responsibilities include assisting the Divisions of ONE Gas, including Texas Gas Service Company ("TGS" or the "Company"), with the review and analysis of company financial data and records and preparation of and participation in rate cases and other regulatory filings and related activities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have filed testimony in proceedings before the Oklahoma Corporation Commission, Kansas Corporation Commission, and the Railroad Commission of Texas ("Commission") regarding the same general subject matters that I am testifying to in this case. A list of the dockets in which I have testified is provided as Exhibit ANE-1.

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

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony provides the analysis and calculations to support the Company's proposed adjustments to Schedule C Plant and Workpaper G-9.c to recover meal costs of $25 or less, exclusive of taxes and the tip amount, and some hotel stays greater than $150 per night, exclusive of taxes.

Q. WHAT SCHEDULES ARE YOU SUPPORTING?

A. I am supporting the following schedules:

Schedule C Plant	Co-Sponsor with Ms. Guerra and Ms. Mindy Edwards
Schedule G-9 Shared Services and Distrigas	Co-Sponsor with Mr. Brown and Ms. Michels

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes, I sponsor the exhibits listed in the table of contents.

Q. ARE ANY OF THE COSTS THAT YOU SPONSOR ALLOCATED FROM ONE GAS OR THE TGS DIVISION?

A. Yes. The Corporate and TGS Division meal and hotel costs that I support in my testimony are all related to centralized services provided to ONE Gas' operating divisions or TGS service areas, including the proposed Central-Gulf Service Area ("CGSA"). These centralized services are provided more efficiently at the Corporate or Division level and are considered "shared service" costs because the services provide support to all ONE Gas' Operating Divisions or TGS service areas. Company witness Anthony Brown discusses in his testimony the methodology and percentages used to allocate these costs to the proposed CGSA.

Q. DO YOU SPONSOR ANY DIRECT PROPOSED CGSA COSTS?

A. Yes. The meal and hotel costs are coded directly to the proposed CGSA.

II. MEAL AND HOTEL ADJUSTMENT

Q. WHERE ARE THE PROPOSED MEAL AND HOTEL ADJUSTMENTS REFLECTED IN THIS STATEMENT OF INTENT?

A. The Company's proposed adjustments to meal and hotel costs are provided in Table 1 below:

Table 1	
Plant Workpapers	**Expense Workpapers**
Workpaper C.a. Direct Plant	Workpaper G-9.c Meal & Hotel
Workpaper C.b TGS Division Plant	
Workpaper C.c Corporate Plant	
Workpaper C-1.a Direct CCNC	
Workpaper C-1.b TGS Division CCNC	
Workpaper C-1.c Corporate CCNC	

Q. PLEASE DESCRIBE THE ADJUSTMENTS IN THE PLANT WORKPAPERS LISTED IN TABLE 1.

A. In addition to the plant adjustments discussed in the direct testimony of Company witnesses Gracie Guerra and Mindy R. Edwards, the plant workpapers listed in Table 1 provide the plant-related amounts of meal, hotel, alcohol, and spouse costs removed from the filing. As discussed in more detail below, the Company included meals under $25 per person, exclusive of taxes and tip amount, hotel stays under $150 per night, exclusive of taxes, and some hotel stays greater than $150 per night, exclusive of taxes.[1]

Q. PLEASE DESCRIBE THE ADJUSTMENTS IN WORKPAPER G-9.C.

A. Workpaper G-9.c includes the expense amounts of meal, hotel, alcohol, and spouse costs removed from the filing. For purposes of the adjustment proposed in this

[1] The Company's Gas Reliability Infrastructure Program Filings have removed meal and hotel costs greater than $25 per person, per meal and $150 per night, exclusive of taxes.

filing, the Company has removed all alcohol and spouse costs and certain meal and hotel costs, as I describe further below.

Q. WHAT ADJUSTMENT IS PROPOSED FOR MEAL AND HOTEL COSTS IN THE TEST YEAR?

A. Following a review of employee meal and hotel costs incurred during the test year, the Company proposes an adjustment of $(16,401) to the test year amount. Table 2, below, provides the amount of per book unadjusted meal and hotel costs, the Company's proposed adjustment, and the adjusted meal and hotel costs incurred during the test year and included in the revenue requirement calculation. The proposed adjustments, excluding some hotel stays greater than $150 per night, exclusive of taxes, are detailed in the Plant Workpapers and Expense Workpaper G-9.c described above.

Table 2

Meal and Hotel Costs Allocated to Proposed CGSA	Per Book Unadjusted	Proposed Adjustment for Test Year	Adjusted Amount Included in Revenue Requirement Calculation
Corporate Plant and CCNC	$14,124	$(179)	$13,945
Shared Services Plant and CCNC	$22,505	$(508)	$21,997
Direct Plant and CCNC	$3,343	$(119)	$3,224
Plant Subtotal	**$39,972**	**$(806)**	**$39,166**
Corporate Expense	$136,867	$(12,072)	$124,795
Shared Services Expense	$166,424	$(2,635)	$163,789
Direct Expense	$243,191	$(888)	$242,303
Expense Subtotal	**$546,482**	**$(15,595)**	**$530,887**
Grand Total	**$586,454**	**$(16,401)**	**$570,053**

Q. PLEASE DESCRIBE THE REVIEW OF MEAL AND HOTEL COSTS YOU MENTIONED ABOVE.

A. In preparation for the adjustment proposed in this statement of intent, the Company began a review of test year meal and hotel costs ("Review") in January 2019. To conduct its Review, the Company developed an Excel spreadsheet beginning with June 30, 2018 per book, unadjusted credit card charges downloaded from ONE Gas' accounts payable system. Each month, the spreadsheet was updated with current credit card charges from the accounts payable system after monthly accounting close until the spreadsheet contained data through the end of the test year period, or June 30, 2019. This manual process allowed the Company to organize and evaluate the reasonableness of all meal costs greater than $25 per person, per meal, exclusive of taxes and tips, and hotel costs greater than $150 per night, exclusive of taxes.

Q. HOW DID THE COMPANY CALCULATE THE AMOUNT OF MEAL COSTS INCLUDED IN THE REVENUE REQUIREMENT?

A. After analyzing the data from the Review, the Company concluded, as shown in Exhibit ANE-2, that approximately 90 percent of the Company's test year meal costs were below $25 per person, per meal, exclusive of tax and tip amounts. The remaining approximately 10 percent of meal costs were evaluated for accuracy, compliance with the Business Travel and Expenditure Policy, and reasonableness. Consistent with the Company's request in this statement of intent related to meal costs and as described by Company witness David Scalf, meal costs greater than $25 per person, per meal, exclusive of taxes and tip amounts were removed. The resulting amount the Company proposes for recovery in the revenue requirement includes meal costs $25 or less, per person, per meal, exclusive of both taxes and the tip amount. This adjustment is provided in Plant Schedule C and Workpaper G-9.c.

Q. HOW DID THE COMPANY CALCULATE THE AMOUNT OF HOTEL COSTS INCLUDED IN THE REVENUE REQUIREMENT?

A. Using the Review data, the Company first identified hotel transactions that were under $150 per night, exclusive of taxes, and determined that those transactions represented approximately 73 percent of the test year hotel costs, as shown on Exhibit ANE-2. The Company conducted a line-by-line review of the remaining hotel stays to evaluate the hotel transactions for accuracy, reasonableness of the business purpose, compliance with the Business Travel and Expenditure Policy, and geographical location. In some cases, the Company requested additional information from the employee responsible for the transaction. As the Company evaluated hotel stays over $150 per night, exclusive of taxes further, it determined that geographical location was a recurring factor.

Q. WHAT AMOUNT OF HOTEL COSTS GREATER THAN $150 PER NIGHT, EXCLUSIVE OF TAXES, ARE INCLUDED IN THE REVENUE REQUIREMENT?

A. Approximately $34,000 of hotel costs greater than $150 per night, exclusive of taxes, are included in the revenue requirement calculation, as shown in Exhibit ANE-2. Over 27% of these costs are from hotel stays in Texas with the majority of the 27% incurred from hotels stays in Austin, Permian Basin, El Paso, Galveston, and Port Arthur, as shown in Exhibit ANE-2. Employee duties necessitating the travel range from line repair, installation and replacement to corporate and division support service and employee management activities. In fact, the analysis confirms that TGS employee job responsibilities are not necessarily restricted to one geographical area. Many employees, especially those in management or Corporate and Division support service roles, have responsibilities that span the entire TGS or ONE Gas footprint.

Q. ARE THERE ANY COST DRIVERS THE COMPANY IDENTIFIED FOR THOSE HIGHER COST HOTELS IN THE LOCATIONS MENTIONED ABOVE?

A. Yes. Based on the Company's experience, certain market factors in Austin, the Permian Basin region, El Paso, Galveston and Port Arthur affect the nightly rate of hotels, resulting in hotel stays over $150 per night, exclusive of taxes.

In the Permian Basin, for instance, hotel rooms have become more difficult to obtain as oil and gas activity in the region has gradually increased over the past decade. The same is true in Port Arthur due to refinery expansions in the area. With respect to Austin, El Paso and Galveston, a primary driver of increased costs appears to be competing events driving tourism. For instance, when employees must travel to Austin and an event or major convention is on-going, obtaining a room for less than $150 is often not possible.

Q. IS THE MEAL AND HOTEL AMOUNT REFLECTED IN THE COMPANY'S FILING REASONABLE?

A. Yes. The Company spent approximately nine months conducting a detailed, manual review of meal and hotel costs and evaluating their reasonableness to support the Company's request to recover these costs. Additionally, from a Company policy perspective, Mr. Scalf discusses revisions to the Business Travel and Expenditure Policy to ensure the overall reasonableness of meal and hotel costs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

ALLISON EDWARDS – LIST OF PRIOR TESTIMONY

Line	Jurisdiction	Docket	Company	Year
1	Oklahoma Corporation Commission	Cause No. PUD 201400069	Oklahoma Natural Gas	2014
2	Oklahoma Corporation Commission	Cause No. PUD 201500213	Texas Gas Service	2015
3	Railroad Commission of Texas	GUD No. 10506	Texas Gas Service	2016
4	Railroad Commission of Texas	GUD No. 10739	Texas Gas Service	2018
5	Kansas Corporation Commission	Docket No. 18-KGSG-560-RTS	Kansas Gas Service	2018
6	Railroad Commission of Texas	GUD No. 10766	Texas Gas Service	2018

	A	B	C	D	E	F	G	H	I
1	**Summary:** Meal Count over/under $25/person								
2	**Test Year:** July 2018-June 2019								
3	**Source:** WKP G-9.c Meal and Hotel Adjustments to Direct SS and Distr(CONFIDENTIAL).xlsx								
4	**Filters Applied:**								
5	Expense Types Column: "Catering" and "Meals"								
6	Comments: Other Column: "Blank"								
7	*These filters were applied to only include meal related charges that were included in this rate filing*								
8									
9	**Meal count over/under $25/person**		**% of Total Meals**						
10	Under	16,102	91%						
11	Over	1,546	9%						
12	**Total**	**17,648**	**100%**						
13									

Summary: Hotel stay frequency by city, state and price range.
Test Year: July 2018-June 2019
Source: WKP G-9.c Meal and Hotel Adjustments to Direct SS and Distr(CONFIDENTIAL).xlsx
Filters Applied:
To Cost Center Column: Excluded CC 1013
Natural Account Column: 4261210, 4261211, 4264102, 9302311
Expense Type Column: Hotel
These filters were applied to only include hotel related charges that were included in this rate filing

Count of Occurrence by Price Range		**Hotel Price Ranges**													
Hotel Location (City)	**Hotel Location (State)**	**< 150**	**150-200**	**200-250**	**250-300**	**300-350**	**350-400**	**400-450**	**450-500**	**500-550**	**550-600**	**600-650**	**700-750**	**800-850**	**Total**
ABILENE	KS	1													**1**
ADDISON	TX	2													**2**
ALBUQUERQUE	NM	4	9												**13**
ALLEN	TX	4													**4**
AMARILLO	TX	2	1												**3**
ANAHEIM	CA			3											**3**
ANDREWS	TX	1			4										**5**
ARDMORE	OK	9													**9**
ARLINGTON	VA	3	3												**6**
ATLANTA	GA	4	27	5	2										**38**
AURORA	CO		7												**7**
AUSTIN	TX	825	150	69	26	20	16	2		1			1	1	**1,111**
BARTLESVILLE	OK	22	2												**24**
BAYTOWN	TX	1													**1**
BEAUMONT	TX	5	2	1											**8**
BEDFORD	TX		2												**2**
BELOIT	KS	1													**1**
Bermuda	UK							6							**6**
BORGER	TX	33													**33**
BOSTON	MA	3					8	2	4				2	4	**23**
BOX ELDER	SD			1											**1**
BOYNTON BEACH	FL	21	1												**22**
BRANSON	MO	1	3												**4**
BRENHAM	TX	8													**8**
BROKEN ARROW	OK	17													**17**
CAMBRIDGE	MA				1	1									**2**
CATHEDRAL CIT	CA	21	4	2	1										**28**
CHANDLER	AZ	2													**2**
CHARLESTON	SC			4		1	2			1					**8**
CHARLOTTE	NC			4											**4**
CHICAGO	IL	4	6	4	30	26				2					**72**
CHICKASHA	OK		1												**1**
CHILDRESS	TX	1													**1**
CLINTON	OK	2													**2**
COLLEGE PARK	GA		1												**1**
COLLEGE STATI	TX	2	2												**4**
COLORADO SPRI	CO	24	4	4											**32**
CONCORDIA	KS	1													**1**
CORONADO	CA			15											**15**
CORPUS CHRIST	TX	2													**2**
DALLAS	TX	27	8	19	2	1	1								**58**
DENTON	TX	2													**2**
DENVER	CO	1	20	11	5										**37**
DERBY	KS	8													**8**
DES MOINES	IA		2												**2**
DES PLAINES	IL	2													**2**
DETROIT	MI		2												**2**
DURANT	OK	14													**14**
EAGAN	MN		2												**2**
EL DORADO	KS	1													**1**
EL PASO	TX	561	147	28											**736**
EMPORIA	KS	6													**6**
ENGLEWOOD	CO			9											**9**
Enid	OK	2													**2**
FOREST CITY	AR	1													**1**

Count of Occurrence by Price Range		Hotel Price Ranges													
Hotel Location (City)	**Hotel Location (State)**	**< 150**	**150-200**	**200-250**	**250-300**	**300-350**	**350-400**	**400-450**	**450-500**	**500-550**	**550-600**	**600-650**	**700-750**	**800-850**	**Total**
FORT MYERS BE	FL	4													**4**
FORT SMITH	AR	2													**2**
FORT WORTH	TX	14	4	44	4	1									**67**
FORTWORTH	TX	1													**1**
FRISCO	TX	19	5		1										**25**
FT LAUDERDALE	FL	2			15		3								**20**
FT WORTH	TX	4													**4**
FT. COLLINS	CO	1													**1**
GALVESTON	TX	231	40	16	1										**288**
GEORGETOWN	TX		9	2	1										**12**
GONZALES	TX	23													**23**
GRAHAM	TX	2													**2**
GRANT	OK	2													**2**
GREAT BEND	KS	7	1												**8**
GREENSBURG	KS	1													**1**
GREENWOOD VIL	CO	2	3												**5**
GUTHRIE	OK	1													**1**
HARLINGEN	TX	240	9												**249**
HENDERSON	NV		6												**6**
HOLLYWOOD	FL	2													**2**
HOUSTON	TX	35	46	3	6										**90**
Hugo	OK	1													**1**
HUTCHINSON	KS	53	10	1											**64**
INDIANAPOLIS	IN		15												**15**
INVER GROVE H	MN		1												**1**
IRVING	TX	21	6	7	14	2									**50**
JACKSON	MI	3	1												**4**
Jamaica Beach	TX		1												**1**
JOPLIN	MO	2													**2**
JUNCTION CITY	KS	4													**4**
KANSAS CITY	MO	12	10	1	2	1									**26**
KEMAH	TX	2													**2**
LA QUINTA	CA			2											**2**
LAKE BUENA VI	FL	1			3										**4**
LAKE CHARLES	LA	1													**1**
LAKE FOREST	CA	5													**5**
LAS VEGAS	NV	9													**9**
LAS VEGAS	NV	38	27	33	17	2									**117**
LAWRENCE	KS	1	1												**2**
LEAGUE CITY	TX	12													**12**
LEAVENWORTH	KS	15	2												**17**
LEAWOOD	KS	13	9	3											**25**
LENEXA	KS	1	3												**4**
LITTLE ROCK	AR	7													**7**
LIVINGSTON	TX	5													**5**
LONDON	UK				4	7									**11**
LONG BEACH	CA	9		3											**12**
LONGVIEW	TX	1													**1**
Los Angeles	CA			2											**2**
LOUISVILLE	KY		2												**2**
MANHATTAN	KS	30	2												**32**
MANHATTAN	NY		1												**1**
MARANA	AZ						4								**4**
MARCO ISLAND	FL				4										**4**
MCALLEN	TX	11	1												**12**
MCKINNEY	TX	1													**1**
MCPHERSON	KS	2													**2**
MEMPHIS	TN	7	3												**10**
MERCEDES	TX	5													**5**
MERRIAM	KS	3													**3**
Miami	FL			9											**9**
Miami	OK	12													**12**
MIAMI BEACH	FL	3		4											**7**
MIDLAND	TX	3	1		3	2	2								**11**

Count of Occurrence by Price Range		Hotel Price Ranges													
Hotel Location (City)	**Hotel Location (State)**	**< 150**	**150-200**	**200-250**	**250-300**	**300-350**	**350-400**	**400-450**	**450-500**	**500-550**	**550-600**	**600-650**	**700-750**	**800-850**	**Total**
MINERAL WELLS	TX	8													**8**
MINNEAPOLIS	MN			6											**6**
MONAHANS	TX	1	2	52	20	10	3								**88**
MONTREAL	QC	2			7										**9**
MOUNT PLEASAN	SC	1		5	1										**7**
MULVANE	KS	4													**4**
NASHVILLE	TN	36	26	39	28	3	3		2						**137**
NEBRASKA CITY	NE	2	2												**4**
NEW BRAUNFELS	TX	8													**8**
NEW CUMBERLAN	PA	21													**21**
New Orleans	LA	7	2		4										**13**
NEW YORK	NY	8		1	12	13	3	12		18		3		2	**72**
NEWPORT	RI	3	3			3									**9**
NORMAN	OK	27			1										**28**
ODESSA	TX	4	1	4	2	6	2	1							**20**
OKLAHOMA CITY	OK	398	65	2	4	3									**472**
OLYMPIC VALLE	CA			1											**1**
OMAHA	NE			2											**2**
ORLANDO	FL	4	10	21	2	5									**42**
OTTAWA	KS	2													**2**
OVERLAND PARK	KS	257	27	3											**287**
OWASSO	OK	38													**38**
PARADISE VALL	AZ			2											**2**
PARIS	TX	3													**3**
PARK CITY	UT	3				6									**9**
PARSONS	KS	10													**10**
PAULS VALLEY	OK	4													**4**
PENSACOLA	FL	1													**1**
PHOENIX	AZ	1	7	23											**31**
PITTSBURG	KS	32	2												**34**
PLANO	TX	6	3												**9**
POINT CLEAR	AL		14												**14**
PORT ARTHUR	TX	269	22	1											**292**
PORTLAND	OR		18	2											**20**
PRATT	KS	6													**6**
RANCHO CORDOV	CA	2													**2**
REDMOND	WA					4									**4**
RICHARDSON	TX	9													**9**
ROGERS	AR	6	1												**7**
ROMULUS	MI		1												**1**
ROSEMONT	IL	1	4												**5**
SALINA	KS	22	8												**30**
SAN ANTONIO	TX	10	31	37		1									**79**
SAN DIEGO	CA	4	5	1	25	2									**37**
SAN FRANCISCO	CA		1	3			11		3						**18**
SAN MARCOS	TX	2	1												**3**
SAVANNAH	GA		3												**3**
SCOTTSDALE	AZ		6	3	12		2								**23**
SEATTLE	WA				3			2							**5**
SEGUIN	TX	1													**1**
SHAWNEE	OK	2	1												**3**
SHAWNEE MSN	KS	2													**2**
SHENANDOAH	TX		4												**4**
SOUTHAVEN	MS	1													**1**
SPRING	TX	1													**1**
ST LOUIS	MO	1													**1**
ST SIMONS ISL	GA	2				2									**4**
ST. LOUIS	MO		3	6											**9**
STILLWATER	OK	23	3												**26**
TAMPA	FL	1	19	6	4	4	3								**37**
TEXAS CITY	TX	1													**1**
THE WOODLANDS	TX	1	2		2				2						**7**
TOPEKA	KS	232	23												**255**
TUCSON	AZ	6		6	2										**14**

Count of Occurrence by Price Range		Hotel Price Ranges													
Hotel Location (City)	**Hotel Location (State)**	**< 150**	**150-200**	**200-250**	**250-300**	**300-350**	**350-400**	**400-450**	**450-500**	**500-550**	**550-600**	**600-650**	**700-750**	**800-850**	**Total**
TULSA	OK	1,788	35	1	7				2						**1,833**
VANCOVER	BC			11											**11**
VERNON	TX	1													**1**
VIENNA	VA	5													**5**
W VALLEY CITY	UT		2												**2**
WASHINGTON	DC	10	6	10	9	39	41	8	2	1	5				**131**
WAXAHACHIE	TX	1													**1**
WEATHERFORD	TX	111	5												**116**
WEBSTER	TX		1												**1**
WEST DES MOIN	IA	2													**2**
WICHITA	KS	146	25	4											**175**
WIND CREST	TX	5													**5**
WINTER PARK	FL			3	1										**4**
WOODINVILLE	WA					1									**1**
WOODWARD	OK	16													**16**
Total		**6,118**	**1,019**	**564**	**292**	**166**	**104**	**33**	**15**	**23**	**5**	**3**	**3**	**7**	**8,352**
Percent of Hotel Stays by Price Range		**73.25%**	**12.20%**	**6.75%**	**3.50%**	**1.99%**	**1.25%**	**0.40%**	**0.18%**	**0.28%**	**0.06%**	**0.04%**	**0.04%**	**0.08%**	**100.00%**

	Hotel Location (State)	**< 150**	**150-200**	**200-250**	**250-300**	**300-350**	**350-400**	**400-450**	**450-500**	**500-550**	**550-600**	**600-650**	**700-750**	**800-850**	**Total**
	TX	2,548	506	283	86	43	24	3	2	1	-	-	1	1	**3,498**
	OK	2,378	107	3	12	3	-	-	2	-	-	-	-	-	**2,505**
	KS	861	113	11	-	-	-	-	-	-	-	-	-	-	**985**
	Total (TX,OK,KS)	**5,787**	**726**	**297**	**98**	**46**	**24**	**3**	**4**	**1**	**-**	**-**	**1**	**1**	**6,988**
	Percent in States of Operation														**84%**

Summary: Hotel Costs Greater than $150 per night, exclusive of taxes, included in the revenue requirement calculation						**Exhibit ANE-2**
Test Year: July 2018-June 2019						
Source: WKP G-9.c Meal and Hotel Adjustments to Direct SS and Distr(CONFIDENTIAL).xlsx						
		A	**B**	**C = A+B**	**D = C x 25.01%**	**E = D x 46.4931%**
Financial Source	**Service Area**	**Hotel over $150/Night**	**Removal of Some Hotel Costs over $150/Night**	**Hotel costs over $150/Night Adjusted, Unallocated**	**Hotel costs over $150/Night Adjusted, Allocated to TGS (25.01%)**	**Hotel Costs over $150/Night Allocated to CGSA, Included in Rev Req Calc (46.4931%)**
Balance Sheet	Central Texas	-		-	-	-
	Gulf Coast	31		31	31	31
	Shared Services	4,415		4,415	4,415	2,053
	Distrigas	5,292		5,292	1,324	615
Balance Sheet Total		**9,739**		**9,739**	**5,770**	**2,699**
Income Statement	Central Texas	5,113		5,113	5,113	5,113
	Gulf Coast	1,282		1,282	1,282	1,282
	Shared Services	28,188	(1,839)	26,348	26,348	10,865
	Distrigas	174,910	(38,289)	136,620	34,169	14,089
Income Statement Total		**209,492**	**(40,128)**	**169,364**	**66,912**	**31,349**
Grand Total		**219,231**	**(40,128)**	**179,103**	**72,682**	**34,049**
						(1)
(1) Includes application of 88.69% O&M factor to Income Statement, calculated on Workpaper G.a.2.a.						

	A	B	C	D
1	**Summary:** Percent of hotel costs that occurred during the test year, by state, greater than $150			
2	**Test Year:** July 2018-June 2019			
3	**Source:** WKP G-9.c Meal and Hotel Adjustments to Direct SS and Distr(CONFIDENTIAL).xlsx			
4	**Filters Applied:**			
5	To Cost Center Column: Exclude CC 1013			
6	Natural Account Column: 4261210, 4261211, 4264102, 9302311			
7	Hotel over $150/Night Column: Exclude zero values			
8	*These filters were applied to exlclude activity that is removed in total in the Expense File.*			
9	**Hotel Location (City)**	**Hotel Location (State)**	**Sum of Hotel over $150/Night**	**Percent of Hotel Costs, by State, over $150/Night**
10	**AUSTIN**	TX	22,549	10.29%
11	**MONAHANS**	TX	9,118	4.16%
12	**EL PASO**	TX	5,044	2.30%
13	**FORT WORTH**	TX	4,443	2.03%
14	**SAN ANTONIO**	TX	3,660	1.67%
15	**DALLAS**	TX	2,543	1.16%
16	**IRVING**	TX	2,535	1.16%
17	**ODESSA**	TX	2,349	1.07%
18	**GALVESTON**	TX	1,996	0.91%
19	**HOUSTON**	TX	1,871	0.85%
20	**MIDLAND**	TX	1,183	0.54%
21	**THE WOODLANDS**	TX	1,098	0.50%
22	**ANDREWS**	TX	548	0.25%
23	**GEORGETOWN**	TX	424	0.19%
24	**PORT ARTHUR**	TX	408	0.19%
25	**FRISCO**	TX	385	0.18%
26	**HARLINGEN**	TX	137	0.06%
27	**BEAUMONT**	TX	116	0.05%
28	**SHENANDOAH**	TX	114	0.05%
29	**WEATHERFORD**	TX	90	0.04%
30	**BEDFORD**	TX	70	0.03%
31	**COLLEGE STATI**	TX	38	0.02%
32	**PLANO**	TX	22	0.01%
33	**SAN MARCOS**	TX	21	0.01%
34	**AMARILLO**	TX	10	0.00%
35	**Jamaica Beach**	TX	9	0.00%
36	**MCALLEN**	TX	7	0.00%
37	**WEBSTER**	TX	5	0.00%
38		**TX Total**		**27.73%**
40		**AL Total**		**0.26%**
42		**AR Total**		**0.00%**
48		**AZ Total**		**10.31%**
50		**BC Total**		**0.27%**
60		**CA Total**		**5.56%**
66		**CO Total**		**1.63%**
68		**DC Total**		**10.54%**
80		**FL Total**		**5.77%**
85		**GA Total**		**1.55%**
87		**IA Total**		**0.01%**
90		**IL Total**		**5.24%**
92		**IN Total**		**0.20%**
105		**KS Total**		**1.16%**
107		**KY Total**		**0.04%**
109		**LA Total**		**0.34%**
112		**MA Total**		**3.57%**
116		**MI Total**		**0.05%**
120		**MN Total**		**0.23%**
124		**MO Total**		**0.55%**
126		**NC Total**		**0.14%**
129		**NE Total**		**0.13%**
131		**NM Total**		**0.04%**
134		**NV Total**		**3.68%**
137		**NY Total**		**8.06%**
145		**OK Total**		**2.20%**
147		**OR Total**		**0.33%**
149		**QC Total**		**0.33%**
151		**RI Total**		**0.53%**
154		**SC Total**		**0.86%**
156		**SD Total**		**0.03%**
159		**TN Total**		**5.71%**
162		**UK Total**		**1.54%**
165		**UT Total**		**0.56%**
167		**VA Total**		**0.03%**
171		**WA Total**		**0.83%**
172		**Grand Total**	**219,231**	**100.00%**
173				

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF ALLISON EDWARDS

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

1. "My name is Allison Edwards. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as a Manager 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 this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Allison Edwards

SUBSCRIBED AND SWORN TO BEFORE ME by the said Allison Edwards on this 9th day of December, 2019

JOANNE C. DAVIS NOTARY # 05009895 EXP. 10/25/21 PUBLIC STATE OF OKLAHOMA

Notary Public in and for the State of Oklahoma

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

STACEY R. BORGSTADT

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

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 a Manager 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. I began my employment with ONEOK, Inc. ("ONEOK") on November 21, 2005, as a project leader in the Internal Audit Department. I began serving in my current position as Manager of Rates and Regulatory Analysis in October 2007 while at ONEOK and have retained that position with ONE Gas since its separation from ONEOK. Prior to my employment at ONEOK, I worked as a Senior Audit Associate at KPMG LLP from January 2004 to November 2005. 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. From June 1996 to August 1998, I served as a corporate accountant for Dollar Rent-A-Car.

Q. PLEASE DISCUSS YOUR DUTIES AND RESPONSIBILITIES AS MANAGER OF RATES AND REGULATORY ANALYSIS.

A. My responsibilities include assisting the Divisions of ONE Gas, including Texas Gas Service Company ("TGS" or the "Company"), with the review and analysis of company financial data and records and preparation of and participation in rate cases and other regulatory filings and related activities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have filed testimony in proceedings before the Oklahoma Corporation Commission, the Kansas Corporation Commission 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 testified is provided as Exhibit SRB-1.

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

A. Yes, it was.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes, I am sponsoring the exhibit listed in the table of contents.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain and support the Company's Direct and Shared Service (TGS Division and Corporate) adjustments associated with:

- base and overtime payroll;

- benefits and payroll related taxes; and
- incentive compensation.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes. I am sponsoring the following schedules:

Schedule G-4 (Base Payroll)
Schedule G-5 (Overtime Payroll)
Schedule G-6 (Benefits & Payroll Related Taxes)
Schedule G-8 (Incentive Compensation)

The schedules I address in my testimony are for the Company's proposed Central-Gulf Service Area ("CGSA"), which is a combination of the existing Central Texas and Gulf Coast Service Areas, as well as the City of Beaumont, Texas. In addition to schedules that reflect the Company's requested consolidation for the proposed CGSA, TGS is also providing stand-alone schedules for the Central Texas and Gulf Coast Service Areas. The stand-alone Gulf Coast Service Area schedules also contain data for customers within the City of Beaumont, Texas.

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

Q. HOW DOES YOUR TESTIMONY RELATE TO OTHER COMPANY WITNESSES IN THIS RATE FILING?

A. My testimony relates to Company witnesses Jeff D. Branz and David Scalf as they support the Company's request to recover incentive compensation costs and they address the new statute, GURA § 104.060. Additionally, the Cost Allocation methodology used in the calculation of these adjustments is supported by Company witness Anthony Brown. In addition, Company witness Shantel Norman supports the overall operations and maintenance ("O&M") expenses and Company witness Gracie Guerra supports the direct expense adjustments.

II. 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 further 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 employees provided to the proposed CGSA as well as employees whose costs are allocated through Shared Services during the test year. Adjusted base salaries were calculated by annualizing test year payroll at June 30, 2019. This adjustment annualizes the changes in the number of employees, promotions, and salary adjustments occurring during the test year. The Company then included an adjustment for the December 2019 Common Salary Review increase, which is the month ONE Gas conducts its annual review of the market-based compensation for each employee and provides any related increases, if applicable. Total test year payroll was then subtracted from the calculated annualized payroll level, including the December 2019 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 CGSA. Mr. Brown discusses the cost allocation methodology and supports the percentages used to allocate these costs to the proposed CGSA. The allocable base payroll adjustment was then assigned to O&M expense accounts based on the accounts to which test year payroll expense was recorded.[1]

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 CGSA, as well as TGS Division and Corporate employees whose costs are allocated through Shared Services. The adjusted hourly base payroll calculated on Schedule G-4 was multiplied by the test year overtime percentage (which is test year overtime as a percentage of test year hourly base pay) to determine annualized overtime payroll. Total test year overtime payroll was then subtracted from the annualized overtime payroll to determine the allocable overtime payroll adjustment. This adjustment was multiplied by allocation factors and the payroll O&M expense ratio to determine the adjusted O&M overtime payroll expense amount applicable to the proposed CGSA. This amount was then assigned to O&M expense accounts based on the accounts to which test year payroll expense was recorded. Overtime pay is a reasonable and necessary component of employee compensation, and it is appropriate to include overtime pay in the annualized payroll amount to be recovered through rates.

[1] The Company will update the adjustment for December 2019 Common Salary Review increases contained on Schedule G-4 with actuals after December 31, 2019 and provide by February 14, 2020.

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 CGSA as well as TGS Division and Corporate employees whose costs are allocated through Shared Services. The adjustment includes a cost per payroll dollar for payroll taxes and for those benefits that vary based on labor cost. Benefits that vary based on labor cost include pension, other post employment benefits, and medical reserve. The benefit cost per payroll dollar was calculated based on the most recently available data for payroll tax and benefits costs. These calculations are shown on Workpaper G-6b. Additional benefits that are not attributable to labor, such as profit sharing amounts, 401(k) company match, tuition reimbursement, and employee assistance programs, are reflected on Schedule G-6 and Workpaper G-6b 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-6b 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 CGSA. This amount was then assigned to O&M expense accounts based on the accounts to which test year payroll expense was recorded as shown on Workpaper G-6a.

III. 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 test year incentive compensation costs. 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).[2] These executive officers are known as the Named Executive Officers in ONE Gas' Notice of Annual Meeting and Proxy Statement. Mr. Scalf and Mr. Branz address GURA § 104.060, provide testimony in support of the reasonableness and necessity of TGS's requested incentive compensation costs, and describe the nature of the ONE Gas incentive compensation plans and the role these plans have in the 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 included in the statement of intent. TGS is seeking recovery of all test year short-term incentive ("STI") and long-term incentive ("LTI") compensation costs for direct employees, TGS Division employees and ONE Gas employees, excluding incentive compensation related to financial metrics for Named Executive Officers.

[2] https://www.sec.gov/divisions/corpfin/ecfr/17cfr229.402a.pdf.

Q. DESCRIBE THE ADJUSTMENT MADE TO STI COMPENSATION.

A. The total per book test year STI costs, including FICA, 401(k) company match, and profit sharing amounts associated with STI, allocated to the proposed CGSA is $3,609,401 of which $(188,962) was attributable to financial metrics for Named Executive Officers. The Company removed the $(188,962) amount consistent with GURA § 104.060 resulting in TGS requesting recovery of $3,420,439. Mr. Branz discusses the STI metrics in his direct testimony.

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 CGSA is $902,593 of which $(316,553) was attributable to financial metrics for Named Executive Officers, resulting in TGS requesting recovery of $586,040. 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 **<u>not</u>** 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.

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

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF STACEY BORGSTADT

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

1. "My name is Stacey Borgstadt. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as a Manager 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 this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Stacey Borgstadt
Stacey Borgstadt

SUBSCRIBED AND SWORN TO BEFORE ME by the said Stacey Borgstadt on this 6 day of December, 2019.

Notary Public in and for the State of Oklahoma

NOTARY SEAL PUBLIC
JARED MIKLES
Notary Public
State of Oklahoma
Commission # 17005926 Expires 06/26/21

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF TIMOTHY S. LYONS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy S. Lyons. My business address is 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 a number of 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., before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden on June 1, 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. A summary of my professional and testimony experience is included in Exhibit TSL-1.

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 Company ("TGS" or the "Company") to develop a lead-lag study that determines the cash working capital ("CWC") requirement for the Company's proposed Central-Gulf Service Area ("CGSA"), which is a combination of the existing Central Texas and Gulf Coast Service Areas and the City of Beaumont, Texas. In addition to schedules that reflect the Company's requested consolidation for the proposed CGSA, TGS is also providing stand-alone schedules for the Central Texas and Gulf Coast Service Areas. Should the Company's request for consolidation not be approved, the City of Beaumont would be included in the stand-alone schedules for the Gulf Coast Service Area. The lead-lag study summary and supporting calculations for the proposed CGSA are included in Exhibits TSL-2 and TSL-3, respectively.

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 RAILROAD COMMISSION OF TEXAS ("COMMISSION") REQUIREMENTS?

A. Yes, the methods used to develop the lead-lag study in this proceeding are consistent with those approved by the Commission in the Company's most recent fully-litigated rate proceeding in Gas Utilities Docket ("GUD") No. 10506.[1]

Q. ARE THE RESULTS OF THE LEAD-LAG STUDY IN THIS PROCEEDING AN ACCURATE ASSESSMENT OF THE COMPANY'S CWC REQUIREMENT?

A. Yes, this lead-lag study is based on the Company's current billing, collection, and payment practices, and thus provides an accurate assessment of the Company's CWC requirements.

III. LEAD-LAG STUDY APPROACH

Q. PLEASE SUMMARIZE 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 $5.0 million for the test year July 1, 2018 through June 30, 2019, adjusted to reflect known and measurable changes through September 30, 2019.

[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 FoF No. 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 CGSA. 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]; West

[2] *Statement of Intent filed by 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).

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]; and Borger-Skellytown Service Area (GUD No. 10766).[8]

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 the Company's other service areas in Texas for the following reasons: (1) the Company was previously directed by the Commission to develop a lead-lag study designed to be applicable to all TGS service areas in Texas; (2) the study is based on data for all of TGS's service areas in Texas; (3) the study 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 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.

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[4] GUD No. 10506, Final Order.

[5] *Statement of Intent of Texas Gas Service Company (TGS), a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area (CTSA) and South Texas Service Area (STSA)*, GUD No. 10526, Final Order (Nov. 15, 2016).

[6] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, GUD No. 10656, Final Order (March 20, 2018).

[7] *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area*, GUD No. 10739, Final Order (Nov. 13, 2018).

[8] *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Borger-Skellytown Service Area*, GUD No. 10766, Final Order (Feb. 5, 2019).

Q. IS THE METHODOLOGY USED TO PREPARE THIS LEAD-LAG STUDY CONSISTENT WITH THE METHODOLOGY USED TO DEVELOP THE STUDY IN GUD NO. 10488?

A. Yes, the methodology used to prepare this lead-lag study is consistent with the methodology used to the develop the study in GUD No. 10488.

Q. PLEASE DESCRIBE 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. PLEASE DESCRIBE THE DATA USED IN THE LEAD-LAG STUDY.

A. The lead-lag study was based on the Company's customer and financial data from July 1, 2018 through June 30, 2019. The data included customer billing and collection data, and payment and expense financial data.

A. Revenue Lag

Q. PLEASE DESCRIBE THE COMPONENTS OF THE REVENUE LAG.

A. The 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 2018) to the payment date. The annual performance bonus is paid annually in March for 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.

2. Current Federal Income Tax Expense

Q. HOW WERE LEAD DAYS FOR FEDERAL INCOME TAXES DETERMINED?

A. Lead days for federal income taxes were based on the number of days from the midpoint of the taxing period (i.e., the calendar year) to the payment date. The payment date reflects scheduled payment dates on April 15, June 15, September 15, and December 15. If the scheduled payment date falls on a Saturday, Sunday, or legal holiday, the payment is due on the next regular business day.

3. Taxes Other than Income Taxes

Q. WHAT TAXES ARE INCLUDED IN 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. PLEASE EXPLAIN WHY YOU EXCLUDED NON-CASH ITEMS FROM YOUR LEAD-LAG STUDY.

A. Consistent with Commission precedent, the lead-lag 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 $5.0 million for the test year July 1, 2018 through June 30, 2019, adjusted to reflect known and measurable changes through September 30, 2019.

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 rate and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim was 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 18 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 and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Recent Assignments

- Sponsored cost of service/rate design testimony for a Mid-Atlantic gas utility. Testimony included a proposal for new residential and commercial rate classes and introduction of a block break rate design.
- Sponsored cost of service/rate design testimony for a Midwest gas utility. Testimony included a proposal for new commercial rate classes and a revenue decoupling mechanism.
- Sponsored cost of service/ rate design and lead-lag testimony for a Midwest gas utility. The testimony included proposals for Revenue Decoupling/ Weather Normalization Mechanism and Tracker Accounts for certain O&M expenses and capital costs.
- Sponsored rate design testimony for a Northeast gas utility. The testimony included: a proposal for zonal rates to promote expansion of natural gas service in the state; market analysis; and financial modeling.
- Led a study for the Massachusetts Department of Energy Resources to evaluate the benefits, costs and policies options associated with natural gas expansion by Massachusetts gas utilities. The study included: (a) research on state regulatory policies; (b) financial modeling and analysis of the economic and environmental impacts of pursuing various policy options; and (c) a survey of Massachusetts homeowners on their opinion of home heating fuels.
- Prepared a transmission and distribution (T&D) avoided cost study and report for a Midwest electric utility. The study was used to support the utility's energy efficiency programs.
- Prepared a review and evaluation of cost of service/ rate design studies for an electric utility. The assignment included review of proposed rate designs that address cost shifting concerns with serving residential distribution generation customers through introduction of higher customer charges, a demand charge and time-of-use energy charges.

- Assisted in the development of an electric portfolio of cost of service, rate design, and rate planning tools. The tools were used to evaluate the impact of future rate filings and resource portfolio decisions on individual rate classes.
- Prepared a market analysis for a utility to evaluate natural gas expansion into new areas, including: (a) survey of homes and businesses; (b) estimate of construction and operating costs; (c) analysis of alternative supply options (including pipeline, LNG and CNG); and (d) financial modeling.
- Directed a process review of natural gas expansion projects for a gas utility. The assignment included a review, evaluation and recommendations related to: (a) policies and procedures; (b) process steps and personnel; (c) financial models and analysis; (d) project decisions and schedules; and (e) post-construction review and evaluation.
- Sponsored lead-lag testimony for several electric and gas utilities.

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Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted testimony and sponsored Lead/Lag study 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			
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 related to: 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			
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
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)	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.

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Sponsor	Date	Docket No.	Subject
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/19	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.
Missouri Public Service Commission			
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.
New Hampshire Public Utilities Commission			
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.

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Sponsor	Date	Docket No.	Subject
New Jersey Board of Public Utilities			
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	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 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

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Sponsor	Date	Docket No.	Subject
			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 – 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.

Texas Gas Service, A Division of One Gas, Inc.
Central-Gulf Service Area
Summary of Lead-Lag Study
Cash Working Capital Requirement

Line	Description	Test Year Amount	Average Daily Amount	Revenue Lag	Ref. (*)	Expense Lag	Ref. (*)	Net (Lead)/Lag Days	Working Capital Requirement
1	Operations and Maintenance Expenses								
2	Purchased Gas Costs	$ 75,042,680	$ 205,596	39.30	A	(40.82)	B	(1.52)	$ (312,837)
3	Labor - Regular Payroll Expense	21,411,135	58,661	39.30	A	(22.75)	C	16.55	970,985
4	Labor - Annual Performance Bonus Expense	4,511,994	12,362	39.30	A	(243.29)	C	(203.99)	$ (2,521,661)
5	Non-Labor - Other O&M Expense	25,396,115	69,578	39.30	A	(39.85)	C	(0.55)	$ (38,271)
6	Total O&M Expenses	$ 126,361,925	$ 346,197						$ (1,901,784)
7	Federal Income Taxes								
8	Current Income Taxes	$ 7,855,526	$ 21,522	39.30	A	(38.50)	D	0.80	17,232
9	Deferred Income Taxes		-	0.00		0.00		0.00	-
10	Total Federal Income Taxes	$ 7,855,526	$ 21,522						$ 17,232
11	Taxes Other Than Income Taxes								
12	FICA	$ 1,531,862	$ 4,197	39.30	A	(12.75)	E	26.55	$ 111,442
13	Federal Unemployment	14,132	39	39.30	A	(30.08)	E	9.22	357
14	State Unemployment	38,180	105	39.30	A	(30.09)	E	9.21	964
15	State Gross Receipts	3,236,984	8,868	39.30	A	(76.14)	E	(36.84)	(326,719)
16	Local Franchise Tax	8,845,495	24,234	39.30	A	(94.26)	E	(54.96)	(1,331,904)
17	State Franchise Tax	1,544,261	4,231	39.30	A	47.71	E	87.01	368,122
18	Ad Valorem	4,385,203	12,014	39.30	A	(199.16)	E	(159.86)	(1,920,553)
19	Sales Tax	4,044,485	11,081	39.30	A	(35.42)	E	3.88	42,950
20	RRC Gas Utility Tax	46,734	128	39.30	A	(89.80)	E	(50.50)	(6,466)
21	Taxes Other Than Income Taxes	$ 23,687,337	$ 64,897						$ (3,061,807)
22	Interest on Customer Deposits	150,792	$ 413	39.30	A	(168.23)	F	(128.93)	$ (53,265)
23	Depreciation Expense	21,681,983	$ 59,403	0.00		0.00		0.00	$ -
24	Return	37,529,690	$ 102,821	0.00		0.00		0.00	$ -
25	Total	$ 217,267,252	$ 595,253						$ (4,999,624)

(*) Corresponds to the spreadsheet tabs in the lead-lag study

Texas Gas Service, A Division of One Gas, Inc.
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	5.47	19.30	39.99	WP A-1	$ 267,768,993	$ 10,707,259,700
2	Commercial	15.21	5.57	16.95	37.73	WP A-2	85,658,244	3,231,751,333
3	Industrial	15.21	6.50	16.58	38.28	WP A-3	2,836,867	108,609,370
4	Public Authority	15.21	6.02	16.83	38.06	WP A-4	19,103,044	727,054,853
5	Transportation	15.21	10.16	16.19	41.56	WP A-5	14,808,946	615,400,013
6	Irrigation	15.21	6.52	17.74	39.47	WP A-6	1,422,064	56,130,575
7	Composite Revenue Collection Days	15.21	5.71	18.53	39.30		$ 391,598,157	$ 15,390,075,269

Texas Gas Service, A Division of One Gas, Inc.
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	July-2018	07/01/18	07/31/18	$ 7,065,658	31.00	(15.50)	(26.59)	(42.09)	$ (297,365,839)	
2	August-2018	08/01/18	08/31/18	7,520,865	31.00	(15.50)	(24.86)	(40.36)	(303,508,862)	
3	September-2018	09/01/18	09/30/18	7,542,960	30.00	(15.00)	(24.66)	(39.66)	(299,128,510)	
4	October-2018	10/01/18	10/31/18	11,081,457	31.00	(15.50)	(26.28)	(41.78)	(462,979,896)	
5	November-2018	11/01/18	11/30/18	15,352,921	30.00	(15.00)	(28.67)	(43.67)	(670,430,521)	
6	December-2018	12/01/18	12/31/18	21,501,968	31.00	(15.50)	(26.01)	(41.51)	(892,596,990)	
7	January-2019	01/01/19	01/31/19	23,740,052	31.00	(15.50)	(25.41)	(40.91)	(971,287,200)	
8	February-2019	02/01/19	02/28/19	15,840,897	28.00	(14.00)	(25.39)	(39.39)	(623,902,835)	
9	March-2019	03/01/19	03/31/19	11,778,650	31.00	(15.50)	(24.68)	(40.18)	(473,230,133)	
10	April-2019	04/01/19	04/30/19	8,421,344	30.00	(15.00)	(27.14)	(42.14)	(354,865,512)	
11	May-2019	05/01/19	05/31/19	6,790,878	31.00	(15.50)	(19.21)	(34.71)	(235,734,589)	
12	June-2019	06/01/19	06/30/19	5,624,104	30.00	(15.00)	(24.55)	(39.55)	(222,419,837)	
13			Total	$ 142,261,755					$ (5,807,450,724)	(40.82)

Texas Gas Service, A Division of One Gas, Inc.
Lead-Lag Study
O&M Expenses

Line	Description	(Lead)/Lag Days	Reference
1	Regular Payroll Expenses	(22.75)	WP C-1
2	Annual Performance Bonus Expense	(243.29)	WP C-1
3	Labor-Related - Subtotal		
4	Other O&M Expenses	(39.85)	WP C-5

Texas Gas Service, A Division of One Gas, Inc.
Lead-Lag Study
Federal Income Tax

							(Lead)/Lag Days	
Line	Quarter	Service Period Start	Service Period End	Midpoint of Service Period	Payment Date	Percent of Taxes Due	Days from Midpoint to Payment Date	(Lead)/Lag Days
1	Third Quarter	1/1/2018	12/31/2018	(182.50)	9/17/2018	25.00%	105.00	(19.38)
2	Fourth Quarter	1/1/2018	12/31/2018	(182.50)	12/17/2018	25.00%	14.00	(42.13)
3	First Quarter	1/1/2019	12/31/2019	(182.50)	4/15/2019	25.00%	260.00	19.38
4	Second Quarter	1/1/2019	12/31/2019	(182.50)	6/17/2019	25.00%	197.00	3.63
5	Federal Income Tax (Lead)/Lag Days							(38.50)

Texas Gas Service, A Division of One Gas, Inc.
Lead-Lag Study
Taxes Other Than Income Tax

Line	Description	(Lead)/Lag Days	Reference
1	FICA	(12.75)	WP E-1
2	Federal Unemployment	(30.08)	WP E-2
3	State Unemployment	(30.09)	WP E-3
4	State Gross Receipts	(76.14)	WP E-4
5	Local Franchise Tax	(94.26)	WP E-5
6	State Franchise Tax	47.71	WP E-6
7	Ad Valorem	(199.16)	WP E-7
8	Sales Tax	(35.42)	WP E-8
9	RRC Gas Utility Tax	(89.80)	WP E-9

Texas Gas Service, A Division of One Gas, Inc.
Lead-Lag Study
Interest on Customer Deposits

Line	Description	Test Year Interest Expense	Average Monthly Interest	Accrued Interest Balance	Composite (Lead)/Lag Days
1	6/1/2018			$ 90,577	
2	7/1/2018		$ 14,930	105,507	
3	8/1/2018		15,428	120,935	
4	9/1/2018		15,428	136,363	
5	10/1/2018		14,930	151,293	
6	11/1/2018		15,428	166,721	
7	12/1/2018		14,930	-	
8	1/1/2019		15,428	15,428	
9	2/1/2019		15,428	30,856	
10	3/1/2019		13,935	44,791	
11	4/1/2019		15,428	60,219	
12	5/1/2019		14,930	75,149	
13	6/1/2019		15,428	90,577	
14	Average			$ 83,724	
15	Interest Expense	$ 181,651			
16	Daily Interest Expense	$ 498			
17	Composite (Lead)/Lag Days				(168.23)

STATE OF VERMONT §
§
§

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 at 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 this 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 7th day of December, 2019.

Notary Public in and for the State of Vermont

NOTARY PUBLIC
VERMONT
Kevin Lemieux

Notary Public State of Vermont
Kevin Lemieux
Commission * No. 157.0008207 *
My Commission Expires January 31,2021

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

JEFF D. BRANZ

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF JEFF D. BRANZ

I. INTRODUCTION AND QUALIFICATIONS

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 ANY REGULATORY COMMISSIONS?

A. Yes, I filed testimony in Gas Utilities Docket Nos. 10739 and 10766 before the Railroad Commission of Texas.

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.

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 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. My testimony will also address how TGS's requested compensation and benefits costs comply with a new Texas law that went into effect in June 2019 related to the reasonableness and necessity of employee compensation and benefit costs for gas utility employees. The new statute, Gas Utility Regulatory Act ("GURA") § 104.060 defines "employee compensation and benefits" to include base salaries, wages, incentive compensation, and benefits. Company witnesses David Scalf and Stacey Borgstadt also address these issues in their direct testimonies.

II. ONE GAS COMPENSATION PHILOSOPHY

Q. PLEASE EXPLAIN ONE GAS' EMPLOYEE COMPENSATION PROGRAM.

A. ONE Gas' employee compensation program is designed to attract, engage, motivate and retain employees. The compensation program includes a combination of a fixed component in the form of base pay and the variable components of incentive compensation, which are comprised of short-term incentives ("STI") and long-term incentives ("LTI"), if applicable. When determining, or setting compensation, ONE Gas' objective is to pay its employees on average at the 50th percentile of the market for total compensation compared to peer companies. As a result, individual pay is differentiated and may be below, at or above the 50th percentile depending on an employee's level of experience or knowledge. 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 a Common 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 most 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 any incentive award. Variable pay plans provide ONE Gas with opportunities to motivate employee performance and attract, engage, reward and retain qualified workers in a safe environment. In this way, incentive compensation plans are designed to encourage productive behavior from plan participants for the benefit of the customers ONE Gas and TGS serve as well as employees and shareholders.

Q. HOW DOES ONE GAS ENSURE THAT ITS COMPENSATION PROGRAMS ARE REASONABLE?

A. ONE Gas participates in national and industry-specific salary surveys to determine proper pay ranges and LTI and STI targets for each position. These surveys 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. Most positions are matched to multiple surveys that are conducted by independent third-party human resources or compensation consulting firms. ONE Gas relies on surveys to establish pay (or market) ranges that are competitive with its peers. This is the type of market-based approach that is specifically addressed in the new statute, GURA § 104.060.

Q. YOU PREVIOUSLY MENTIONED GURA §104.060. HOW DOES THE COMPANY'S USE OF MARKET STUDIES RELATE TO THE NEW LAW?

A. The new law states that the regulatory authority shall presume that employee compensation and benefits expenses are reasonable and necessary if the expenses are consistent with market compensation studies issued not earlier than three years before the initiation of the proceeding to establish the rates. Section 104.060 defines "employee compensation and benefits" to include base salaries, wages, incentive compensation, and benefits while excluding pension or other post-employment benefits, and financially-based incentive compensation related to Named Executive Officers.[1] As I explain below, ONE Gas relies on recent market studies to assess the reasonableness of the compensation it offers employees and the base pay, incentive, and benefits ONE Gas offers employees are consistent with those market studies. For those reasons, the costs TGS is requesting are presumed reasonable and necessary based on the new statute.

Q. WOULD YOU PROVIDE SOME EXAMPLES OF THE SURVEYS USED TO MONITOR MARKET-BASED PAY RELATED TO ONE GAS EMPLOYEES?

A. The surveys used to monitor market-based pay include:

- Willis Towers Watson General Industry;
- Willis Towers Watson Energy Executive Compensation;
- Willis Towers Watson American Gas Association Compensation;
- CompData Utilities;
- Mercer Energy Total Compensation;
- Mercer Benchmark;
- Southern Gas Association; and
- Willis Towers Watson Energy Services Mid-Management, Professional and Support.

Several of these recent surveys and survey excerpts are included in my testimony exhibits.

[1] Named Executive Officers are officers whose compensation is required to be disclosed under 17 C.F.R. Section 229.402(a) and they are specifically referenced as Named Executive Officers in ONE Gas' Notice of Annual Meeting and Proxy Statement.

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 employees. The Executive Compensation Committee of ONE Gas' Board of Directors and its independent executive compensation consultant, Meridian Compensation Partners, LLC, review market data of ONE Gas' peers. The peers are selected because of their similarities to ONE Gas, including the 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's 2019 Proxy Statement on page 51, 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 Willis Towers Watson 2019 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, demonstrate that ONE Gas and TGS salaries and incentives are generally below the median of market. Specifically, Willis Towers Watson found "Texas Gas' overall compensation levels, short-term at-risk compensation design, and long-term at-risk compensation design to be reasonably competitive with market practices, based on multiple market perspectives we examined." Willis Towers Watson'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 has been providing incentive compensation to 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 2018 American Gas Association Compensation Survey excerpt - Bonuses and Other Variable Pay Programs reports that 63.6% of respondents in the survey that are distribution companies such as TGS offer STI to non-exempt employees, 75% to exempt employees, 76.9% to management, and 84.6% to executives (Confidential Exhibit JDB-3);

- The 2018 American Gas Association Compensation Survey excerpt - Long-Term Incentives reports that 68.1% of the 47 respondents in their survey offer LTI (Confidential Exhibit JDB-4);

- The Willis Towers Watson 2019 Long-Term Incentives Policies and Practices Survey U.S. excerpt - LTI Prevalence found that 68.6% of the 102 energy companies responding granted restricted LTI and 92.2% granted performance-based LTI (Confidential Exhibit JDB-5); 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, and (4) increased difficulty recruiting and retaining new employees. 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 and safe 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, 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.

III. COMPENSATION COMPONENTS

Q. WHAT ARE THE COMPENSATION COMPONENTS?

A. Compensation is comprised of several components, including base pay and incentive programs commonly known as STI and LTI. STI and LTI are commonly referred to as at-risk pay. STI is awarded to all employees based on meeting specific metrics and provides meaningful incentives for employees to operate with an emphasis on safety and customer service along with ONE Gas' financial performance. LTI is awarded to a select group of employees. ONE Gas also offers benefits such as health and welfare and retirement plans, which are considered part of the overall employee compensation 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, and cost of living 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 Common 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 specifically to encourage productive employee behavior that leads to positive safety, operational and financial results for the benefit of customers. In addition, ONE Gas is a 100% regulated natural gas utility, which means that all ONE Gas and TGS employees, from executive management in Tulsa, Oklahoma to front line employees in the proposed Central-Gulf Coast Service Area, are focused solely on providing service to customers.

IV. SHORT TERM INCENTIVE PLAN

Q. PLEASE EXPLAIN ONE GAS' STI PLAN.

A. The Annual Employee Incentive Plan provides for an annual, lump-sum cash amount based on certain employee and ONE Gas performance criteria that are established each year by the ONE Gas Board of Directors' Executive Compensation Committee. 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 ONE Gas performance modifier times the individual STI target (determined by position based on market studies) times the employee's individual performance modifier. For any of the four individual STI metrics to contribute toward an incentive payout, ONE Gas must achieve at least threshold performance for the metric. Provided a level at or above the threshold is attained, the determination of an individual's STI amount may be increased or decreased based on individual performance. Any metric for which the threshold is not achieved will not contribute toward an incentive payout.

STI provides employees with an incentive to provide high quality and safe delivery of service to our customers, which also affects ONE Gas' performance. It is designed to motivate employees to operate safely and efficiently in their day-to-day activities. The Compensation Study provided in Confidential Exhibit JDB-2, page 8, 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-6a and JDB-6b.

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"), diluted earnings per share ("EPS"), and average emergency response time ("AERT").

Q. WHAT METRICS MUST ONE GAS AND EMPLOYEES MEET TO RECEIVE STI?

A. An STI award is made if threshold levels for ONE Gas performance for TRIR, PVIR, DART, AERT, or EPS are attained. Employee performance also affects individual STI awards.

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 8, reflects that 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, some 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, we would run the risk of 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.

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, 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 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 not awarded at all. Conversely, there may be some employees who receive a larger incentive if they exceed performance expectations. This, of course, is reasonable as employees who excel should be recognized for the ways in which their actions contribute to the overall safety, operational efficiency, and quality of service delivered to our customers, as well as the financial health of ONE Gas.

Q. CAN YOU PROVIDE PAYOUT EXAMPLES FOR EMPLOYEES IN THE STI PLAN?

A. Below are actual examples of employee STI payouts for a Field Tech II and a Customer Service Representative II, which are employees who regularly interact with and serve customers. The Field Tech II in the example below had $40,750 in base wages and a 4% incentive target. The Customer Service Representative II had $29,126 in base wages and a 4% incentive target. The company performance resulted in a company modifier of 121.2%. 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 Tech II - Pipeline/Field Support										
Base Wages Earned	**x**	**STI Incentive Target**	**x**	**Individual Modifier**	**x**	**Company Modifier**	**=**	**STI**
$40,750	x	4%	x	95%	x	121.2%	=	**$1,877**
Customer Service Rep II - Information Center								
Base Wages Earned	**x**	**STI Incentive Target**	**x**	**Individual Modifier**	**x**	**Company Modifier**	**=**	**STI**
$29,126	x	4%	x	95%	x	121.2%	=	**$1,341**

As the examples demonstrate, the Field Technician II 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 amounts of STI pay are reasonable and also a valuable component of 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 the company into first quartile performance thus benefiting ONE Gas, TGS, and its customers, as discussed in the testimony of Company witness Shantel Norman.

V. LONG TERM INCENTIVE PLAN

Q. PLEASE EXPLAIN THE LTI PLAN.

A. ONE Gas has an LTI Plan in which two types of LTI equity awards (grants of ONE Gas stock), are available to executives and certain key employees. Of the 135 LTI participants who received a grant in February 2019, 84% were non-officers. In the payout that vested in February 2019, 81% of the employees were non-officers. ONE Gas' LTI plan is included as Confidential Exhibit JDB-7 to my testimony. LTIs 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 2019, 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 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 performance, employee potential, long-term value to ONE Gas, criticality of the job and our desire to retain quality employees are considered in determining employee eligibility. LTI awards vest three years after the grant to encourage long-term improvements and financial awareness in key employees and to provide an incentive to remain employed with ONE Gas.

The Compensation Study provided in Confidential Exhibit JDB-2, at page 3, identifies that ONE Gas' long-term at-risk compensation is comparable to and competitive with plan designs of other similarly sized utilities. For that reason, these costs are presumed reasonable and necessary under GURA § 104.060.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN RESTRICTED STOCK UNITS AND PERFORMANCE STOCK UNITS.

A. Restricted Stock Units are granted for a term of three years from the date of the grant, with the participant being vested and entitled to receive one share of ONE Gas common stock for each restricted stock unit granted after three years of employment following the grant date. Restricted Stock Units are time-based equity and are not based on the financial performance of ONE Gas; rather, it is a form of compensation that depends entirely on an employee's tenure with ONE Gas. Restricted Stock Units are designed to encourage the retention of key employees, reducing turnover and retaining experienced employees who contribute to the overall success and stability of the organization.

Performance Stock Units also vest three years from the date of the grant, at which time the employee is entitled to receive a percentage of the Performance Stock Units granted in shares of ONE Gas common stock. The number of shares of common stock awarded will range from 0% to 200% of the number of units granted based upon ONE Gas' performance as measured by its three-year total shareholder return ("TSR") compared with a designated peer group of 13 utility peer companies 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, engage, motivate, and retain 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 contribute significantly 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 awarding 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 70.2% of energy companies using that metric according to the Willis Towers Watson 2019 Long-Term Incentives Policies and Practices Survey U.S. excerpt - LTI Prevalence provided in Confidential Exhibit JDB-5. Thus, the ONE Gas LTI plan design that relies on TSR is the most common approach among the majority of peer companies and is evaluated annually to ensure that ONE Gas remains competitive with the market.

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 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 the Company if we did not compensate them competitively in the market.

VI. GENERAL BENEFITS

Q. WHAT ARE THE COMPONENTS OF ONE GAS' BENEFIT PLANS?

A. ONE Gas provides a range of benefits to its employees that include: (a) medical and dental insurance; (b) basic life insurance; (c) basic accidental death and dismemberment; (d) an Employee Assistance Program; (e) 401(k) plan; (f) Profit Sharing Plan or Retirement Plan; and (g) an Employee Stock Purchase Plan. See Confidential Exhibit JDB-8 and Confidential Exhibit JDB-9 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, engage, motivate, and retain 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 high quality health care vendors to provide high quality service to our employees and their dependents while helping ONE Gas to control health care costs.

In addition, employees are required to identify whether they use tobacco products. Those who do pay a premium surcharge. 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. ONE Gas also offers a tobacco cessation program for employees who wish to stop smoking or using tobacco products. The tobacco surcharge, in turn, reduces ONE Gas administration and claims costs.

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 firms 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 market studies that are less than three years old to analyze and decide which benefits to offer. ONE Gas's benefits are consistent with those studies, which means the benefit costs TGS is requesting are presumed reasonable and necessary. See Confidential Exhibit JDB-10 for an independent study showing the value of ONE Gas' benefits is comparable to peer companies and slightly above the median value.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

SCHEDULE 14A
(Rule 14A – 101)

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
☒ Definitive Proxy Statement
☐ **Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))**
☐ Definitive Additional Materials
☐ Soliciting Material Pursuant to §240.14a-12

ONE Gas, Inc.
(Name of Registrant as Specified In Its Charter)

(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

Payment of Filing Fee (Check the appropriate box):

☒ No fee required.

☐ Fee computed on table below per Exchange Act Rules 14a-6(i)(1) and 0-11.

(1) Title of each class of securities to which transaction applies:

(2) Aggregate number of securities to which transaction applies:

(3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (set forth the amount on which the filing fee is calculated and state how it was determined):

(4) Proposed maximum aggregate value of transaction:

(5) Total fee paid:

☐ Fee paid previously with preliminary materials.

☐ Check box if any part of the fee is offset as provided by Exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

(1) Amount Previously Paid:

(2) Form, Schedule or Registration Statement No.:

(3) Filing Party:

(4) Date Filed:

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ONE Gas

Annual Meeting of Shareholders
Thursday, May 23, 2019

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ONE Gas

MISSION

We deliver natural gas for a better tomorrow.

VISION

To be a premier natural gas distribution company creating exceptional value for our stakeholders.

STRATEGY

Becoming ONE:

- **ONE in Responsibility – safety, reliability and compliance**
- **ONE in Value – employees, shareholders, customers and communities**
- **ONE in Industry – recognized leader, processes and productivity**

CORE VALUES

- **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. Honesty, trust and integrity matter.
- **Inclusion and 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.

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ONE Gas

April 3, 2019

Dear Shareholder:

You are cordially invited to attend the Annual Meeting of Shareholders of ONE Gas, Inc., which will be held at 9:00 a.m. Central Daylight Time on Thursday, May 23, 2019, at our company headquarters at ONE Gas, Inc., First Place Tower, 15 E. Fifth Street, 2nd Floor, Tulsa, Oklahoma 74103.

The matters to be considered and voted on at the meeting are set forth in the attached Notice of Annual Meeting of Shareholders and are described in the attached proxy statement. A copy of our 2018 annual report to shareholders is also enclosed. A report on our 2018 performance will be presented at the meeting.

We look forward to greeting as many of our shareholders as possible at the annual meeting. We know, however, that most of our shareholders will be unable to attend. 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 on 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.

YOUR VOTE IS IMPORTANT – 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 for your continued support.

Sincerely,

John W. Gibson.

JOHN W. GIBSON
Chairman of the Board

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ONE Gas

ONE GAS, INC. NOTICE OF 2019 ANNUAL MEETING OF SHAREHOLDERS

Time and date: May 23, 2019, at 9:00 a.m. Central Daylight Time

Place: ONE Gas, Inc., First Place Tower, 15 E. Fifth Street, 2nd Floor, Tulsa, Oklahoma 74103

Items of business:

(1) To consider and vote on the election of nine 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, 2019;

(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 25, 2019. 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

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. The instructions in the accompanying proxy statement and attached to your proxy card describe how to use these convenient voting methods. Of course, if you prefer, you may vote by mail by completing your proxy card and returning it in the enclosed postage-paid envelope. You may revoke your proxy at any time by following the procedures set forth in the accompanying proxy statement.

Whether or not you expect to attend the meeting in person, we urge you to vote your shares at your earliest convenience. This will ensure the presence of a quorum at the meeting. Voting your shares promptly, via the internet, by telephone, or by signing, dating and returning the enclosed proxy card 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: This notice of annual meeting, proxy statement, form of proxy and our 2018 annual report to shareholders are available on our website at www.ONEGas.com. Additionally, and in accordance with the rules of the SEC, you may access this proxy statement and our 2018 annual report at http://shareholder.onegas.com, which does not infringe on the anonymity of a person accessing such website. The website does not employ "cookies" or other user-tracking features.

The approximate date of the mailing of this proxy statement and accompanying proxy card is April 3, 2019.

By order of the Board,

Brian K. Shore

Brian K. Shore
Corporate Secretary

Tulsa, Oklahoma
April 3, 2019

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PROXY STATEMENT

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 2019 Annual Meeting of Shareholders to be held at the time and place set forth in the accompanying notice.

Unless we otherwise indicate or unless the context indicates otherwise, all references in this proxy statement to "ONE Gas", "we," "our," "us," the "company" or similar references mean ONE Gas, Inc. and its subsidiaries, and references to the "Board" or "Board of Directors" mean the Board of Directors of ONE Gas, Inc.

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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
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CIC	Change in control
Company or ONE Gas	ONE Gas, Inc.
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
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
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 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
SIF	Significant Incidents or Fatalities
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

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SUMMARY PROXY INFORMATION

To assist you in reviewing the company's 2018 performance and voting your shares, we would like to call your attention to key elements of our 2019 proxy statement and our 2018 annual report to shareholders. The following is only a summary. For more complete information about these topics, please review the complete proxy statement and our 2018 annual report to shareholders.

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 23, 2019
- **Time:** 9:00 a.m., Central Daylight Time
- **Place:** ONE Gas, Inc., First Place Tower, 15 E. Fifth Street, 2nd Floor, Tulsa, Oklahoma 74103

ITEMS OF BUSINESS

- Election of nine director nominees to serve a one-year term
- Ratification of the selection of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2019
- 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

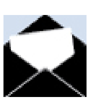
- March 25, 2019

INTERNET ACCESS TO PROXY MATERIALS

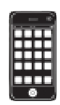
- Please visit http://shareholder.onegas.com for online access to our proxy materials including this proxy statement and the company's 2018 annual report.

HOW TO VOTE IF YOU ARE A SHAREHOLDER OF RECORD

Via the internet
- Go to the website at www.proxypush.com/ogs which is available 24 hours a day, 7 days a week, until 11:59 p.m. (Central Daylight Time) on May 22, 2019.
- 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 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.



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 22, 2019.
- 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.**

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HOW TO VOTE IF YOUR SHARES ARE HELD BY A BROKER, BANK OR OTHER HOLDER OF RECORD

- This proxy statement and our 2018 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 nine 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 2018 executive compensation. Our Board recommends that shareholders **vote in favor** of our executive compensation program.

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PROPOSALS, BOARD RECOMMENDATIONS, HOW YOU MAY VOTE, 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?	How may I vote?	Votes required for approval when quorum is present	Abstentions	Broker non-votes
1. Election of Directors	The Board recommends that you vote **FOR** each of the nine director nominees.	You may vote **FOR** or **AGAINST** the approval of each of the nine director nominees, or you may indicate that you wish to **ABSTAIN** from voting on the matter.	Majority of the votes cast by shareholders present in person or by proxy and entitled to vote	Do not count as votes cast and have no effect on the vote	Do not count as votes cast and have no effect on the vote
2. Ratification of our Independent Auditor	The Board recommends that you vote **FOR** the ratification of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2019.	You may vote **FOR** or **AGAINST** the ratification of the selection of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2019, or you may indicate that you wish to **ABSTAIN** from voting on the matter.	Affirmative vote of a majority of the voting power of the shareholders present in person or by proxy and entitled to vote	Have the same effect as votes against this proposal	Voted at broker's discretion – shares not voted in the discretion of a brokerage firm, bank, trustee or other similar fiduciary have the same effect as votes against this proposal
3. Advisory vote on Executive Compensation	The Board recommends that you vote **FOR** the approval, on an advisory basis, of the company's executive compensation.	You may vote **FOR** or **AGAINST** the advisory vote on executive compensation, or you may indicate that you wish to **ABSTAIN** from voting on the matter.	Affirmative vote of a majority of the voting power of the shareholders present in person or by proxy and entitled to vote	Have the same effect as votes against this proposal	Do not count as votes cast and have no effect on the vote

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DIRECTOR NOMINEES

The following table summarizes information about the nine director nominees. As noted, seven of our nine directors have been determined to be independent in accordance with the NYSE independence standards and our director independence guidelines.

Director Nominees

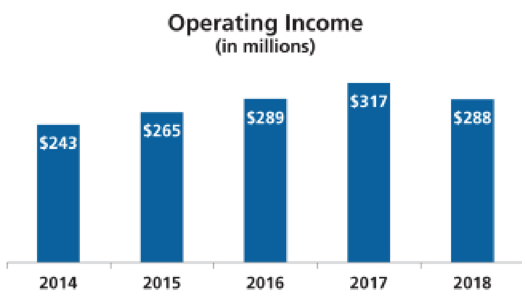
Name	Age	Director since	Occupation	Independent	Committee memberships/ positions
Arcilia C. Acosta	53	2018	President and Chief Executive Officer, CARCON Industries and Construction	Yes	B, C, D
Robert B. Evans	70	2014	Retired, President and Chief Executive Officer of Duke Energy Americas	Yes	B**, C, D
John W. Gibson	66	2014	Retired, Chief Executive Officer of ONEOK	No	A*
Tracy E. Hart	57	2018	President, Tarlton Corporation	Yes	B, C, D
Michael G. Hutchinson	63	2014	Retired, partner at Deloitte & Touche	Yes	A, B*, C, D**
Pattye L. Moore	61	2014	Chairman, Red Robin Gourmet Burgers	Yes	A, B, C*, D
Pierce H. Norton II	59	2014	President and Chief Executive Officer of ONE Gas, Inc.	No	A
Eduardo A. Rodriguez	63	2014	President of Strategic Communication Consulting Group	Yes	A, B, C, D*
Douglas H. Yaeger	70	2014	Retired, Chairman, President and Chief Executive Officer of The Laclede Group, Inc. (now known as Spire Inc.)	Yes	B, C**, D

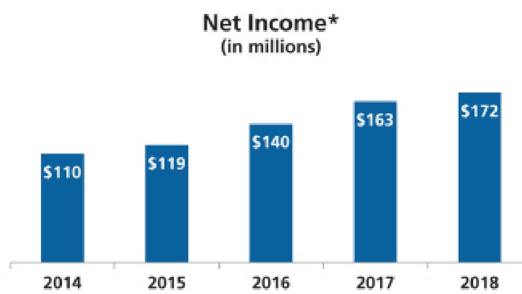
Committee memberships/positions key:

A Executive Committee
B Audit Committee
C Executive Compensation Committee
D Corporate Governance Committee
* Committee chair
** Committee vice chair

BUSINESS HIGHLIGHTS

- **Financial Performance.** 2018 operating income decreased to $288.4 million, compared with $316.7 million in 2017, which reflects primarily new rates in Texas and Kansas and residential customer growth in Oklahoma and Kansas, higher sales and transportation volumes due to colder than normal weather, offset by an increase in operating expenses and the effects of tax reform.





* We were a business unit of ONEOK prior to January 31, 2014.

- **Dividend.** During 2018, we paid cash dividends of $1.84 per share. We paid total aggregate dividends to our shareholders of $97 million in 2018. In January 2019, we declared a dividend of 50 cents per share ($2.00 per share on an annualized basis), an increase of 4 cents per share compared with the previous cash dividend of 46 cents per share.

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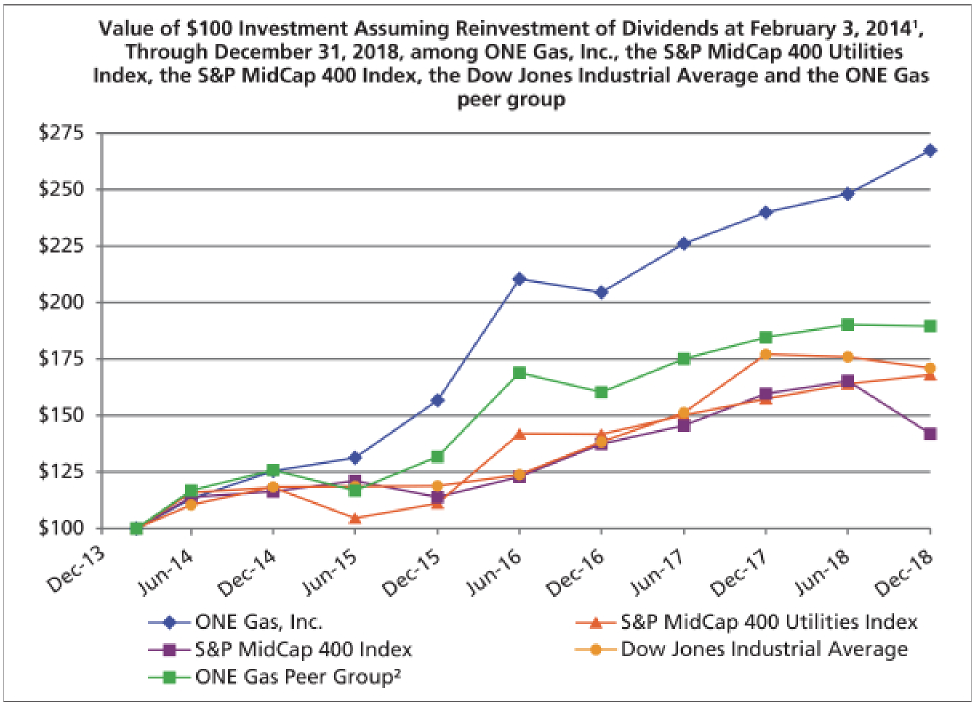
- **Total Shareholder Return.** The market price of our common stock was $79.60 per share at December 31, 2018, reflecting a TSR (stock price appreciation and dividends) of 11.40 percent and an increase of 8.7 percent from the closing price of $73.26 on December 29, 2017.



1 February 3, 2014 was the first day of "regular way" trading for ONE Gas, Inc. on the NYSE.

2 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 2018 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 Gas Company; NorthWestern Corporation; South Jersey Industries; Southwest Gas Corporation; and Spire Inc.

COMPENSATION HIGHLIGHTS

- **Compensation Philosophy.** A principal feature of our compensation program is the determination of executive compensation by our Executive Compensation Committee (referred to as the "Executive Compensation Committee" or the "Committee") 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, to pay for performance and to align the long-term interests of our executive officers with those of our stakeholders. We believe our program is designed effectively to meet or exceed our financial and operational performance goals, is well aligned with the interests of our stakeholders and is instrumental to achieving our business goals. Our compensation philosophy and related governance features are complemented by several specific elements that are designed to achieve these objectives, as summarized below.

- **Program Design.**

  Our compensation program:

  – provides a competitive total compensation opportunity;

  – establishes a pay mix that balances short- and long-term performance specifically consisting of significant equity-based (at-risk) compensation;

  – utilizes separate metrics under our STI and LTI award programs to incentivize performance;

  – links a significant portion of total compensation to performance which we believe creates long-term stakeholder value;

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- – determines awards based on the executive officer's contributions performed the right way to achieve business performance;
- – enhances retention by subjecting a significant portion of total compensation to multi-year vesting requirements;
- – discourages unnecessary or excessive risk taking;
- – rewards for accomplishing goals as well as for how those goals are accomplished; and
- – restricts CIC cash benefits to double-trigger vesting.

- We provide the following primary elements of compensation for our NEOs (as listed in the Compensation Discussion and Analysis at page 40): base salary, annual STI awards and LTI awards.
- The Executive Compensation Committee references the median level of the market when determining all elements of compensation and targets the median level of total compensation.
- Our performance-based STI program provides for cash awards based on achievement of financial and operational goals established annually by our Executive Compensation Committee.
- We encourage alignment of our NEOs' interests with those of our stakeholders through the grant of LTI awards, of which approximately 80 percent are PSUs and approximately 20 percent are RSUs.
- Our NEOs receive no significant perquisites or other personal benefits.
- We do not provide any "golden parachute" excise tax gross-ups to our NEOs.
- The Executive Compensation Committee makes all compensation decisions regarding our NEOs and submits those decisions to the independent directors of the Board for ratification.
- The Executive Compensation Committee is composed solely of persons who qualify as independent directors under the listing standards of the NYSE.
- 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.
- We have adopted compensation recovery ("clawback") provisions that permit the Committee to use appropriate discretion to seek recoupment of grants of PSUs (including any shares earned and the proceeds from any sale of such shares) and STI awards paid to an employee in the event that fraud, negligence or individual misconduct by such employee is determined to be a contributing factor to having to restate all or a portion of our financial statements.
- Officers, members of our Board and certain employees designated as insiders under our Securities/Insider Trading Policy are prohibited from engaging in short sale and other derivative or speculative transactions in our securities, and/or from purchasing or using, directly or indirectly through family members or other persons or entities, financial instruments (including puts or calls, prepaid variable forward contracts, equity swaps, collars and exchange funds) that are designed to hedge or offset any decrease in the market value of our securities.
- Officers and directors are prohibited from holding our securities in a margin account or pledging our securities as collateral for a loan. The CEO may grant an exception against pledging securities on a limited case-by-case basis. There is no exception to the prohibition against pledging with respect to the CEO.
- The Executive Compensation Committee engages an executive compensation consultant who is independent under the SEC rules and NYSE listing standards to provide advice and expertise on our executive and director compensation program design and implementation and to lead discussions on trends within our industry.
- Our say-on-pay vote in 2018 was 96.7 percent in agreement with our compensation paid to our NEOs. In reviewing our compensation program during 2018, our Executive Compensation Committee determined to continue to apply the same principles as have been historically applied in determining the nature and amount of our executive compensation.

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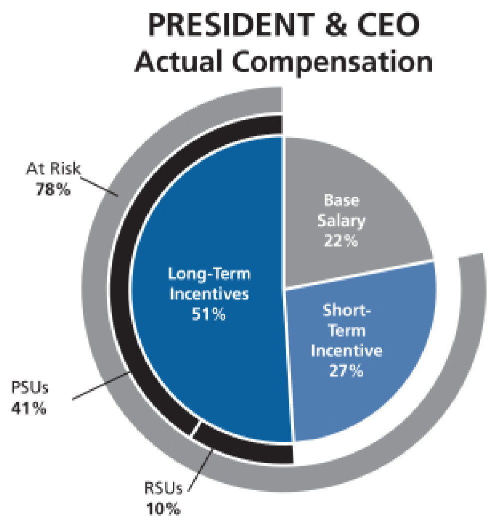
- **Link between Executive Compensation and Performance.** The Board awarded Pierce H. Norton II, our President and CEO, incentive compensation for 2018 that was commensurate with our business results and his position as our President and CEO, including annual base pay of $775,000, an annual STI award of $939,300, and a LTI award with a grant target value of $1,750,000. Consistent with our executive compensation philosophy, a significant majority of Mr. Norton's total direct compensation of $3,464,300 for 2018 was incentive-based and at-risk, as illustrated by the following chart:



The compensation of our other NEOs further reflects both our 2018 performance and our pay-for-performance compensation philosophy:

Named Executive Officer	2018 Base Salary	2018 STI Award	2018 LTI Award *	2018 Total Direct Compensation
Pierce H. Norton	$775,000	$939,300	$1,750,000	$3,464,300
Curtis L. Dinan	$435,000	$363,255	$425,040	$1,223,295
Caron A. Lawhorn	$365,000	$301,924	$400,022	$1,066,946
Robert S. McAnnally	$365,000	$301,924	$400,022	$1,066,946
Joseph L. McCormick	$340,000	$242,509	$375,003	$957,512

* Represents the grant date value approved by the Committee. The values displayed in the Summary Compensation Table represent the accounting value of the PSUs.

Name	2018 Target STI Award as Percentage of Base Pay	2018 Maximum STI Award as a Percentage of Base Pay
Pierce H. Norton II	100%	188%
Curtis L. Dinan	65%	122%
Caron A. Lawhorn	65%	122%
Robert S. McAnnally	65%	122%
Joseph L. McCormick	55%	103%

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CORPORATE RESPONSIBILITY

For more than 100 years, our business has delivered natural gas to our customers. We will continue to focus on operating safely and responsibly, while creating shareholder value. For more information see our Corporate Responsibility report published on our website at www.ONEGas.com.

SAFETY AND HEALTH

The safety of our employees, our customers and the communities where we operate is at the forefront of each business decision we make. 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.

A substantial part of our workforce is comprised of operations specialists who work regularly in the field. We continuously assess the risks our employees face in their jobs, and we work to mitigate those risks through training, appropriate engineering controls, work procedures and other preventive safety and health programs. Reducing incidents and improving our safety incident rates is important, but we are not focused only on statistics. Low incident rates alone cannot prevent a large-scale incident, which is why we continue to focus on enhancing our preventive safety programs, such as near-miss reporting, vehicle-safety monitoring, risk assessment and others.

2018 Safety and Health Performance Updates and Highlights

- Since 2013 we have experienced a 57% reduction in our TRIR.
- Since 2013 strains and sprains, our most prevalent type of injury, has declined by 85%.
- Since 2013 we have experienced a 75% reduction in our DART.
- Since 2013 we have experienced a 23% reduction in our PVIR.

ENVIRONMENTAL PERFORMANCE

2018 Environmental Updates and Highlights

- We retired or replaced approximately 430 miles of distribution and transmission facilities in 2018, including 21 miles of cast iron pipe, which will result in decreased emissions of methane. We have a total of four miles of cast iron pipe remaining to be replaced, which we have committed to replace by the end of 2019.
- In 2018, our Energy Efficiency Program in Oklahoma and the Austin and Rio Grande Valley Conservation Programs in Texas combined to issue more than 122,750 rebates totaling approximately $17 million through energy-efficiency and conservation programs that offered customers rebates on natural gas appliances and energy-efficient home improvements.
- We continue to be a partner in the EPA's Natural Gas STAR Program and the EPA's Methane Challenge program to voluntarily reduce greenhouse gas emissions. We anticipate reporting in 2019 our 2018 performance to the EPA. We exceeded our goal by achieving an overall replacement rate between 6 and 7 percent in both 2017 and 2016.

COMMUNITY INVESTMENT

We are committed to being active members of the communities where we operate. Investing in the areas where we have operations and where our employees live and work is not only the right thing to do–it's smart business. By contributing financially and through volunteer work, we can help build stronger communities and create a better environment for our employees, our customers and the general public.

We accomplish this in a number of ways, including grants from the ONE Gas Foundation, corporate sponsorships to nonprofit organizations and community volunteer efforts. Primary focus areas for our community investments are education, health and human services, arts and culture, environmental stewardship and community enrichment. We give priority consideration to educational programs and to health and human services organizations, particularly those with programs that help people become self-sufficient.

2018 Community Investment Updates and Highlights

- In 2018, we contributed approximately $2.1 million to nonprofit organizations through the ONE Gas Foundation and corporate sponsorships, and our employees volunteered more than 9,500 hours in our communities.

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POLITICAL ADVOCACY AND CONTRIBUTIONS

We actively participate in the political process through the lobbying efforts of our government relations department, involvement in multiple business and industry trade organizations, and through the ONE Gas PAC. In 2018, ONE Gas employees and members of the ONE Gas Board contributed approximately $95,719 to the ONE Gas PAC. During 2018, the ONE Gas PAC contributed approximately $121,250 to candidates for political office and other political action committees.

As a company, we do not contribute corporate funds to political candidates, political action committees or so-called 501(c)(4) social welfare organizations. Employee and director contributions to the ONE Gas PAC are used to support candidates seeking federal or state offices who support the interests of the energy industry and business. A steering committee made up of senior management representatives and a contributions committee made up of employees from across our operating areas oversee all ONE Gas PAC contributions to political candidates.

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OUTSTANDING STOCK AND VOTING

VOTING

Only shareholders of record at the close of business on March 25, 2019, are entitled to receive notice of and to vote at the annual meeting. As of that date, 52,686,558 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 in person 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 nine 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, 2019; 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 in person 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 25, 2019.

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, EQ Shareholder Services, a division of Equiniti Trust Company, 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 in person 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 in person 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 nine 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, 2019;

(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.

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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 2019 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, 2019. In accordance with our bylaws, approval of this proposal requires the affirmative vote of a majority of the voting power of the shareholders present in person 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 the proposal to approve our executive compensation requires the affirmative vote of a majority of the voting power of the shareholders present in person 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 at the meeting in person. 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, 470 West Avenue, Stamford, Connecticut 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.

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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; 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 of Directors 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 of Directors 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 Arcilia C. Acosta, 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.

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BOARD LEADERSHIP STRUCTURE

During 2018, 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 of Directors 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 Norton 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, 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, 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.

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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 governance, compensation, safety, environmental 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 presenting at 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 organization, 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.

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 relating to significant acquisitions, risk oversight is addressed as part of the full Board's engagement with the CEO and management.

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.

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. 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 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.

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During 2018, the Board held nine regular meetings (six in-person and three telephonic meetings) and no special meetings. All of our incumbent directors who served on the Board during 2018 attended more than 75 percent of the aggregate 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. All then-current members of the Board attended the 2018 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
Arcilia C. Acosta	Member	Member	Member	Member	
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
Pattye L. Moore	Member	Member	Chair	Member	Member
Pierce H. Norton II	Member				Member
Eduardo A. Rodriguez	Member	Member	Member	Chair	Member
Douglas H. Yaeger	Member	Member	Vice Chair	Member	
Number of meetings in 2018	9	6	4	4	0

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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

2018 Meetings: 6

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 evaluating the adequacy of our internal controls 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; 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 Arcilia C. Acosta, Robert E. Evans, Tracy E. Hart, Michael G. Hutchinson, Eduardo A. Rodriguez and Douglas H. Yaeger are each an audit committee financial expert under the applicable rules of the SEC and all members of the Audit Committee are financially literate and six of the seven committee members are audit committee financial experts. No member of our Audit Committee serves on the audit committees of more than three other public companies.

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THE EXECUTIVE COMPENSATION COMMITTEE

2018 Meetings: 4

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; 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 2018, 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 2018 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 42.

THE CORPORATE GOVERNANCE COMMITTEE

2018 Meetings: 4

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;
- in consultation with our Chairman of the Board and CEO and the Executive Compensation Committee, overseeing management succession and development; 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.

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THE EXECUTIVE COMMITTEE

2018 Meetings: 0

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.

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; 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 2020 annual meeting should send a letter of recommendation to our corporate secretary at our principal executive offices by no later than December 5, 2019. 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 necessary for our Board to determine 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, sex, race, 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 2020 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 2019 Annual Meeting of Shareholders (i.e., notice must be received no later than December 5, 2019). If the date of the 2020 annual meeting is more than 30 days from the first anniversary date of the 2019 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

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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 in person 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 December 2017 indicating that our non-management director compensation was significantly below

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market median compared to our peers, coupled with the decision of the Executive Compensation Committee to consider non-management director compensation on a three-year basis, the Executive Compensation Committee recommended and the full Board approved non-management director compensation on a three-year cycle. For the period of May 24, 2018, through May 22, 2019, non-management director compensation consists of $85,000 in an annual cash retainer and a $110,000 stock retainer. The chairs of our Audit and Executive Compensation Committees receive an additional annual cash retainer of $15,000, and our lead independent director, who is also chair of our Corporate Governance Committee, receives an additional annual cash retainer of $30,000. Our Chairman of the Board receives an additional annual cash retainer of $85,000 for his service. Non-management director compensation will next be considered in 2020.

Upon their election in July 2018, Mesdames Acosta and Hart received pro-rata non-management director compensation for the period from July 23, 2018, through May 22, 2019.

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) 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. Mesdames Acosta and Hart have 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 2018:

Director Compensation for 2018

Director	Fees Earned or Paid in Cash(1)	Stock Awards (1)(2)(3)	Nonqualified Deferred Compensation Earnings(4)	All Other Compensation(5)	Total
Arcilia C. Acosta	$ 70,950	$ 91,818	$ -	$ -	$162,768
Robert B. Evans	$ 85,000	$110,000	$ -	$ -	$195,000
John W. Gibson	$170,000	$110,000	$3,823	$20,000	$303,823
Tracy E. Hart	$ 70,950	$ 91,818	$ -	$ -	$162,768
Michael G. Hutchinson	$100,000	$110,000	$ -	$ -	$210,000
Pattye L. Moore	$100,000	$110,000	$ -	$ 5,000	$215,000
Eduardo A. Rodriguez	$115,000	$110,000	$ -	$ -	$225,000
Douglas H. Yaeger	$ 85,000	$110,000	$ -	$ -	$195,000

(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, 2018, $365,612 of the total amount payable for directors' fees were deferred under this plan at the election of five 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, 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 2, 2018, was 4.52 percent. The following table sets forth, for each non-management director, the amount of director compensation deferred during 2018 and cumulative deferred compensation as of December 31, 2018.

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Director	Board Fees Deferred to Phantom Stock in 2018 (a)	Dividends Earned on Phantom Stock and Reinvested in 2018 (b)	Total Board Fees Deferred to Phantom Stock at December 31, 2018 (a)	Total Shares of Phantom Stock Held at December 31, 2018	Board Fees Deferred to Cash in 2018 (c)	Total Board Fees Deferred to Cash at December 31, 2018 (c)
Arcilia C. Acosta	$ 81,384	$ 466	$ 81,850	1,018	$ -	$ -
Robert B. Evans	$ -	$ -	$ -	-	$ -	$ -
John W. Gibson	$ 110,000	$ 17,413	$ 540,307	10,362	$ 170,000	$ 907,984
Tracy E. Hart	$ 36,727	$ 442	$ 37,169	485	$ -	$ -
Michael G. Hutchinson	$ -	$ -	$ -	-	$ -	$ -
Pattye L. Moore	$ 110,000	$ 17,413	$ 540,307	32,945	$ -	$ -
Eduardo A. Rodriguez	$ 27,500	$ 885	$ 46,864	1,331	$ -	$ -
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) Mr. Gibson deferred board fees in the amount of $170,000 to cash in 2018. 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 2, 2018, was 4.52 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 2018 for service on our Board.

Director	Shares Awarded in 2018	Aggregate Grant Date Fair Value
Arcilia C. Acosta	1,142	$ 91,818
Robert B. Evans	1,512	$110,000
John W. Gibson	1,512	$110,000
Tracy E. Hart	1,198	$ 91,818
Michael G. Hutchinson	1,512	$110,000
Pattye L. Moore	1,512	$110,000
Eduardo A. Rodriguez	1,512	$110,000
Douglas H. Yaeger	1,512	$110,000

(3) For the aggregate number of shares of our common stock and phantom stock held by each member of our Board at March 1, 2019, see "Stock Ownership–Holdings of Officers and Directors" at page 38.

(4) Reflects above-market earnings on Board of Directors 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, 2018, was 4.52 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.

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COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

During 2018, Mesdames Acosta, 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 2018, and no member of this committee was formerly an officer of the company or its subsidiary. In addition, during 2018, 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 2018, 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 2018, 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.

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PROPOSAL 1 – ELECTION OF DIRECTORS

ELECTION BY MAJORITY VOTE

In conjunction with the 2018 Annual Meeting of Shareholders, our shareholders approved our Amended and Restated Certificate of Incorporation, which among other things, declassified our Board such that all directors are elected annually for one-year terms. Therefore, all nine current directors are standing for election for one-year terms.

Recognizing the need to ensure an appropriate balance of experience, expertise and perspective on our Board, in July 2018 our Board, based on the recommendation of our Corporate Governance Committee, elected two new directors: Arcilia C. Acosta and Tracy E. Hart. Mesdames Acosta and Hart bring a wealth of experience in project management, construction, executive management, operations and strategic and financial planning to the Board. Your Board of Directors 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.

If no directors receive the requisite majority vote at an annual or special meeting held for the purpose of electing directors where the election is uncontested, then, pursuant to our corporate governance guidelines, the incumbent Board will, within 180 days after the certification of the shareholder vote, nominate a new slate of directors and hold a special meeting for the purpose of electing those nominees. In this circumstance, the incumbent Board will continue to serve until new directors are elected and qualified.

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 2018, the Board appointed two highly qualified female directors, bringing the total females on the Board to three (33%). Our Board is also comprised of two Hispanic directors (Ms. Acosta and Mr. Rodriguez)(22%). The Board is also diverse in terms of age, with ages ranging from 53 to 70. Average director tenure is slightly over four 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, race, gender, age and nationality, and to maintain a mix that includes, but is not limited to, the following areas of core

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competency: accounting and finance; investment banking; business judgment; management; industry knowledge; crisis response; international business; leadership; strategic vision; law; and corporate relations.

Your 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:

		Board Skills and Qualifications																				Committees			
	Independent?	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		Executive Committee	Audit Committee	Executive Compensation Committee	Corporate Governance Committee
John W. Gibson	N	●	●	●	●	●	●		●											●		C			
Arcilia C. Acosta	Y	●	●			●		●										●	●	●			M	M	M
Robert B. Evans	Y	●	●	●			●	●	●				●							●			VC	M	M
Tracy E. Hart	Y	●	●			●	●											●		●			M	M	M
Michael G. Hutchinson	Y	●		●												●	●			●		M	C	M	VC
Pattye L. Moore	Y	●				●				●	●	●										M	M	C	M
Pierce H. Norton II	N	●	●	●	●	●	●	●	●										●	●		M			
Eduardo A. Rodriguez	Y	●		●		●				●				●	●					●		M	M	M	C
Douglas H. Yaeger	Y	●	●	●				●	●	●	●									●			M	VC	M

C = Committee chair
VC = Committee vice-chair
M = Committee member

Certain information with respect to the nine 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 nine 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.

YOUR BOARD UNANIMOUSLY RECOMMENDS A VOTE FOR EACH NOMINEE.

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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.

ARCILIA C. ACOSTA

Age: 53
Director Since: 2018
Independent: Yes

Ms. Acosta currently serves as the President and Chief Executive Officer of CARCON Industries and Construction, a Dallas based firm specializing in commercial, industrial and transportation design and build construction, and has since 2000. She is also the founder and Chief Executive Officer of Southwestern Testing Laboratories, L.L.C., a geotechnical engineering and construction materials testing firm established in 2003.

Ms. Acosta is a director of Legacy Texas Financial Group, N.A., a bank holding company with an asset size of over $7.5 billion and more than 50 retail branches in Texas, since 2013. Ms. Acosta was elected to the board of Magnolia Oil and Gas Corporation (previously known as TPG Pace Energy Holdings Corp.) in May 2017. In 2008, Ms. Acosta joined the Board of Directors of Energy Future Holdings Corporation and served for over ten years until 2018. She is also a member of the national Women Energy Directors Network.

An accomplished business leader, Ms. Acosta's qualifications to serve on our Board of Directors includes extensive experience providing executive leadership in engineering and construction projects, operations and safety matters. She is an experienced entrepreneur, nationally recognized speaker, philanthropist and top executive recognized by several publications and organizations. In 2014, Ms. Acosta was inducted into the National Women's Business Hall of Fame and Texas Diversity Council named her "Most Powerful and Influential Woman in Texas." In March 2016, the Governor of Texas appointed Ms. Acosta to the Texas Higher Education Coordinating Board.

Ms. Acosta's qualifications to serve on our Board of Directors includes her leadership positions and her experience in executive management, operations, safety, construction management and engineering management. In light of Ms. Acosta's extensive executive managerial experience and her operational skills, our Board of Directors has concluded that Ms. Acosta should continue as a member of our Board.

Committee Member: Audit, Corporate Governance, Executive Compensation

Board skills and qualifications:

- Executive management
- Operations
- Construction management
- Accounting and financial expertise
- Safety
- Strategic and financial planning
- Engineering management

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ROBERT B. EVANS

Age: 70
Director Since: 2014
Independent: Yes

Mr. Evans was elected to the board of Targa Resources Corp. on March 1, 2016, and appointed Chairman of the Risk Management Committee and as a member of its Compensation Committee. Mr. Evans has served as a director of Targa Resources GP LLC, a subsidiary of Targa Resources Corp. and the general partner of Targa Resources Partners, LP since 2007. Mr. Evans has been on the Board of Directors of New Jersey Resources Corp. since 2009 and currently serves as a member of its Audit Committee and Executive Committee. Mr. Evans was also a member of the Board of Directors of Sprague Resources, LP from 2013 until October 1, 2018.

Mr. Evans was 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.

Mr. Evans' extensive executive experience with the natural gas transmission business and wholesale natural gas trading business of Duke Energy and Targa Resources Partners provide him with valuable industry experience. Mr. Evans' service on board positions for other energy companies brings executive, corporate development, operations, finance, customer perspectives, safety, compliance, risk management and industry knowledge to the board. In light of Mr. Evans' extensive industry experience, and his numerous senior management positions where he gained extensive experience in corporate development, operations and financial matters, our Board has concluded that Mr. Evans should continue as a member of our Board.

Committee Member: Audit (Vice Chair), Corporate Governance, Executive Compensation

Board skills and qualifications:

- Executive management
- Operations
- Industry knowledge
- Risk management and oversight
- Corporate development
- Accounting and financial expertise
- Compliance
- Safety

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JOHN W. GIBSON

Position: Chairman of the Board

Age: 66
Director Since: 2014
Independent: No

Mr. Gibson is the non-executive Chairman of the Board of ONE Gas. Mr. Gibson is also the non-executive Chairman of the Board of ONEOK. Mr. Gibson served as Chairman of the Board of ONEOK Partners, L.P., until its acquisition 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. In April 2016, Mr. Gibson joined the board of Matrix Service Company.

Mr. Gibson joined ONEOK in 2000 as President of Energy, responsible for the company's natural gas gathering and processing, and transportation and storage businesses. In 2006, he was named President and Chief Operating Officer of ONEOK Partners, the master limited partnership that owns midstream natural gas and natural gas liquids businesses. He was elected Chief Executive Officer of ONEOK and President and Chief Executive Officer of ONEOK Partners in January 2007, becoming Chairman of ONEOK Partners later that year. In January 2010, he became President of ONEOK, and in May 2011, he became Chairman.

His career began in the energy industry in 1974 as a refinery engineer with Exxon Company, USA. 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. Prior to joining ONEOK, Mr. Gibson was Executive Vice President of Koch Energy, Inc., a subsidiary of Koch Industries, responsible for its interstate natural gas pipelines and gathering and processing businesses.

Mr. Gibson had direct responsibility for and extensive experience in strategic and financial planning, acquisitions and divestitures, operations, management supervision and development, and compliance. Over the course of his lengthy career in a variety of sectors of the oil and gas industry, Mr. Gibson has gained extensive management and operational experience and has demonstrated a strong track record of leadership, strategic vision and risk management. In light of Mr. Gibson's role as the top executive officer at ONEOK and ONEOK Partners and his extensive industry and managerial experience and knowledge, our Board of Directors has concluded that Mr. Gibson should continue as a member of our Board.

Committee Member: Executive (Chair)

Board skills and qualifications:

- Executive management
- Operations
- Industry knowledge
- Acquisitions and divestitures
- Strategic and financial planning
- Risk management and oversight
- Compliance
- Accounting and financial expertise

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TRACY E. HART

Age: 57
Director since: 2018
Independent: Yes

Ms. Hart currently serves as President and Chief Executive Officer and on the board of Tarlton Corporation, a St. Louis based general contracting and construction management firm. She is the first woman to become president of a major general contracting company in St. Louis, and one of a few nationally. Since joining the company in 1990, Tarlton has tripled its size and further solidified its market share.

Ms. Hart recently joined Midwest BankCentre's Legal Board of Directors and is also a member of the Board of Trustees for Webster University. She has served on the Executive Committee of the Board of Directors for the St. Louis Regional Chamber since 2002 and has chaired both the Business Services and Energy & Environment committees. Ms. Hart also serves on the Board of Trustees at St. Louis Children's Hospital, having recently chaired the Community Benefit Committee. She was also a Commissioner of the St. Louis Science Center where she served as the Facilities Committee Chairman and Chairman of the Finance Committee. Ms. Hart served on the board of The Municipal Theatre Association of St. Louis and served as the secretary and on the Executive Committee.

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 is active in the community and 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's qualifications to serve on our Board of Directors includes her leadership positions and her experience in executive management, finance, operations and risk management. In light of Ms. Hart's extensive executive managerial experience and her leadership skills, our Board of Directors has concluded that Ms. Hart should continue as a member of our Board.

Committee Member: Audit, Corporate Governance, Executive Compensation

Board skills and qualifications:

- Executive management
- Operations
- Construction management
- Risk management and oversight
- Strategic and financial planning
- Accounting and financial expertise

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MICHAEL G. HUTCHINSON

Age: 63
Director Since: 2014
Independent: Yes

Mr. Hutchinson has served on the board of Westmoreland Coal Company since 2012 and in November 2017 became its interim Chief Executive Officer. He is also a member of its Executive Committee. 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. Mr. Hutchinson served on the board of CoBiz Financial, Inc. from May 2017 until its acquisition by Bank of Oklahoma in September 2018.

Westmoreland Coal Company filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code on October 9, 2018, in the U.S. Bankruptcy Court for the Southern District of Texas, Houston Division.

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 has substantial expertise in accounting and finance matters gained during his experience in public accounting. He served as the lead audit partner on many of the firm's largest clients in Denver from 1989 until his retirement.

Mr. Hutchinson's qualifications include his experience with accounting principles, financial controls and evaluating financial statements of public companies in the energy sector, particularly from an auditor's perspective. As a result of his experience, Mr. Hutchinson is qualified to analyze the various financial and operational aspects of our company.

In light of Mr. Hutchinson's extensive experience with accounting principles, financial controls and evaluating financial statements of public companies in the energy sector and his ability to analyze the various financial and operational aspects of our company, our Board has concluded that Mr. Hutchinson should continue to serve as a member of our Board.

Committee Member: Audit (Chair), Corporate Governance (Vice Chair), Executive Compensation, Executive

Board skills and qualifications:

- Accounting and financial expertise
- Industry knowledge
- Executive management
- Financial and operational analysis
- Public accounting

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PATTYE L. MOORE

Age: 61
Director Since: 2014
Independent: Yes

Ms. Moore currently serves as the non-executive Chairman of the Board of Red Robin Gourmet Burgers (NASDAQ: RRGB). 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, including Executive Vice President, Senior Vice President-Marketing and Brand Development and Vice President-Marketing. Ms. Moore has extensive senior management, marketing, business strategy, brand development and corporate governance experience as a result of her service at Red Robin, ONEOK, Inc. and Sonic, her service on other boards and her consulting career. In her role as President of Sonic Corp., Ms. Moore was responsible for company and franchise operations, purchasing and distribution, marketing and brand development for the 3,000 unit chain with over $3 billion in system-wide sales. As a business strategy consultant and as a board member, Ms. Moore has extensive experience in leadership, management development, strategic planning and executive compensation. 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. In light of Ms. Moore's extensive executive management, corporate governance and compensation experience and her leadership skills, our Board of Directors has concluded that Ms. Moore should continue as a member of our Board.

Committee Member: Executive Compensation (Chair), Corporate Governance, Audit, Executive

Board skills and qualifications:

- Executive management
- Corporate governance
- Executive compensation
- Marketing
- Strategic and financial planning

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PIERCE H. NORTON II

Position: Management Director

Age: 59
Director Since: 2014
Independent: No

Mr. Norton is President and Chief Executive Officer of ONE Gas.

Prior to the separation, Mr. Norton served as Executive Vice President and Chief Operating Officer of ONEOK and ONEOK Partners. Before that, Mr. Norton was President of the ONEOK Distribution Companies – Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service. Also, while at ONEOK, he held the position of Executive Vice President of Natural Gas, which included responsibility for all natural gas pipelines and the natural gas gathering and processing businesses within ONEOK Partners.

Mr. Norton began his natural gas industry career in 1982 at Delhi Gas Pipeline, a subsidiary of Texas Oil and Gas Corporation. He later worked for American Oil and Gas with operational responsibilities for natural gas gathering and processing, and for intrastate and interstate pipelines. Mr. Norton then worked for KN Energy as Vice President and General Manager of the Heartland Region, before moving to Bear Paw Energy as Vice President of Business Development. In 2002, he was named President of Bear Paw Energy (a subsidiary of Northern Border Partners at the time) now ONEOK Rockies Midstream (a subsidiary of ONEOK Partners).

Mr. Norton is a member of the American Gas Association's board of directors and served as its 2017 Chairman. He currently serves as a board member of the Tulsa Community College Foundation, the Tulsa Community Foundation and the Oklahoma Center for Community and Justice. He is a past board member of the Interstate Natural Gas Association of America, the Texas Pipeline Association, the North Dakota Petroleum Council and the Western Energy Alliance, formerly known as the Independent Petroleum Association of Mountain States. He also is a graduate of Harvard Business School's Advanced Management Program.

Mr. Norton has served in a variety of roles of continually increasing responsibility at ONEOK and ONEOK Partners from November 2004 to January 2014. In these roles, Mr. Norton has had direct responsibility for and extensive experience in strategic and financial planning, acquisitions and divestitures, operations, management supervision and development, and compliance. Mr. Norton has significant experience in assessing acquisition opportunities and in structuring, financing and completing merger and acquisition transactions. In addition, during the course of his lengthy career in a variety of sectors of the oil and gas industry, Mr. Norton gained extensive engineering management, compliance, safety, management and operational experience and has demonstrated a strong track record of leadership, strategic vision and risk management. In light of his lengthy career in a variety of sectors of the oil and gas industry, during which Mr. Norton has gained extensive management and operational experience and has demonstrated a strong track record of leadership, strategic vision and risk management, our Board has concluded that Mr. Norton should continue to serve as a member of our Board.

Committee Member: Executive

Board skills and qualifications:

- Executive management
- Operations
- Industry knowledge
- Risk management and oversight
- Accounting and financial expertise
- Compliance
- Strategic and financial planning
- Acquisitions and divestitures
- Safety
- Engineering management

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EDUARDO A. RODRIGUEZ

Position: Lead Independent Director

Age: 63
Director Since: 2014
Independent: Yes

Mr. Rodriguez is a member of the ONEOK board and serves as Vice Chair of its Executive Compensation Committee and as Vice Chair of its Corporate Governance Committee and is former chair of its Audit Committee. Mr. Rodriguez is President of Strategic Communication Consulting Group in El Paso, Texas. Mr. Rodriguez previously served as Executive Vice President of Hunt Building Corporation, a privately held company engaged in construction and real estate development headquartered in El Paso, Texas. 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, 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. Mr. Rodriguez 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.

Mr. Rodriguez has had extensive senior management, operational, entrepreneurial and legal experience in a variety of industries as a result of his service at Strategic Communication Consulting Group, Hunt Building Corporation and El Paso Electric Company. Mr. Rodriguez has engaged in the practice of law for over 30 years. In addition to his extensive legal experience, Mr. Rodriguez's senior management positions have included responsibility for strategic and financial planning, corporate governance, regulatory compliance, customer service and safety matters. In these positions he has demonstrated a strong track record of achievement and sound judgment. In light of Mr. Rodriguez's extensive legal experience, and his numerous senior management positions where he gained extensive experience in strategic planning, corporate governance and regulatory compliance, our Board has concluded that Mr. Rodriguez should continue to serve as a member of our Board.

Committee Member: Corporate Governance (Chair), Audit, Executive Compensation, Executive

Board skills and qualifications:

- Executive management
- Corporate governance
- Regulatory compliance
- Accounting and financial expertise
- Strategic and financial planning
- Legal
- Industry knowledge

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DOUGLAS H. YAEGER

Age: 70
Director since: 2014
Independent: Yes

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.

After spending nearly 20 years in the interstate pipeline industry, including roles as Executive Vice President of Mississippi River Transmission Corporation and Executive Vice President of Arkla Energy Marketing Company, Mr. Yaeger joined Laclede in 1990 as Vice President–Planning. He was elected Laclede's Senior Vice President–Operations, Gas Supply and Technical Services in 1992. In 1995, Mr. Yaeger was elected Executive Vice President–Operations and Marketing and subsequently in 1997 elected President and Chief Operating Officer and joined Laclede's board.

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. Mr. Yaeger currently serves on the boards of FB Corporation and The Municipal Theatre Association of St. Louis.

Mr. Yaeger has extensive senior management experience in a variety of sectors in the oil and natural gas industry as a result of his service at Laclede where he demonstrated a strong track record of leadership and sound judgment. As a result of his experience, Mr. Yaeger is qualified to analyze the various financial and operational aspects of our company. In light of Mr. Yaeger's extensive industry, financial, compliance, safety, corporate governance, operating and compensation experience, our Board of Directors has concluded that Mr. Yaeger should continue as a member of our Board.

Committee Member: Executive Compensation (Vice Chair), Audit, Corporate Governance

Board skills and qualifications:

- Executive management
- Operations
- Industry knowledge
- Accounting and financial expertise
- Corporate governance
- Executive compensation
- Compliance
- Safety

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PROPOSAL 2 – RATIFY THE SELECTION OF PRICEWATERHOUSECOOPERS LLP AS OUR INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR THE YEAR ENDING DECEMBER 31, 2019

RATIFICATION OF THE SELECTION OF PRICEWATERHOUSECOOPERS LLP AS OUR INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2019

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 2019. In carrying out its duties in connection with the 2018 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 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 in person or by proxy and entitled to vote on this proposal at the meeting. Abstentions will have the effect of a vote against the proposal.

YOUR BOARD UNANIMOUSLY RECOMMENDS A VOTE FOR THE RATIFICATION OF THE SELECTION OF PRICEWATERHOUSECOOPERS LLP AS OUR INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2019.

AUDIT AND NON-AUDIT FEES

Audit services provided by PricewaterhouseCoopers LLP during the 2018 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 year ended December 31, 2018:

	2018	2017
	(Thousands of Dollars)	
Audit fees(1)	$1,124.5	$971.9
Audit related fees(2)	$6.4	$-
Tax fees	$-	$-
All other fees(3)	$36.6	$35.3
Total	$1,167.5	$1,007.2

(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.

(3) All other fees include fees for a professional education seminar for company personnel.

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 2019 audit, a plan was submitted to and approved by the Audit Committee setting forth the audit services expected to be rendered during 2019. 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;

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- 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.

2019 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 six of the seven 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 Public Company Accounting Oversight Board (United States) Auditing Standard No. 1301, Communications with Audit Committees, and Rule 2-07 of the SEC's Regulation S-X ("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. While non-audit services provided by PricewaterhouseCoopers LLP were not significant in 2017 or 2018, and thus, 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.

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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, 2018, in the company's Annual Report on Form 10-K for the year ended December 31, 2018, 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
Arcilia A. Acosta, Member
Tracy E. Hart, Member
Pattye L. Moore, Member
Eduardo A. Rodriguez, Member
Douglas H. Yaeger, Member

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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, 2019.

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	6,267,260(1)	11.90%(1)
Common Stock	The Vanguard Group, Inc. 100 Vanguard Blvd. Malvern, PA 19355	5,214,348(2)	9.92%(2)
Common Stock	T. Rowe Price Associates, Inc. 100 E. Pratt Street Baltimore, MD 21202	4,470,984(3)	8.50%(3)
Common Stock	American Century Investment Management, Inc. 4500 Main Street, 9th Floor Kansas City, MO 64111	2,856,575(4)	5.44%(4)

(1) Based upon Schedule 13G filed with the SEC on January 31, 2019, in which BlackRock, Inc. reported that, as of December 31, 2018, BlackRock, Inc. beneficially owned in the aggregate 6,267,260 shares of our common stock. Of such shares, BlackRock, Inc. reported it had sole dispositive power with respect to 6,267,260 shares and sole voting power with respect to 6,139,792 shares.

(2) Based upon Schedule 13G filed with the SEC on February 11, 2019, in which The Vanguard Group, Inc. reported that, as of December 31, 2018, 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 5,214,348 shares of our common stock. Of such shares, The Vanguard Group, Inc. reported it had sole dispositive power with respect to 5,148,832 shares, shared dispositive power with respect to 65,516 shares, sole voting power with respect to 61,043 shares, and shared voting power with respect to 19,320 shares.

(3) Based upon Schedule 13G filed with the SEC on February 14, 2019, in which T. Rowe Price Associates, Inc. reported that as of December 31, 2018, T. Rowe Price Associates, Inc. beneficially owned in the aggregate 4,470,984 shares of our common stock. Of such shares, T. Rowe Price Associates, Inc. reported it had sole dispositive power with respect to 4,470,984 shares and sole voting power with respect to 985,947 shares.

(4) Based upon Schedule 13G filed with the SEC on February 11, 2019, in which American Century Investment Management, Inc., reported that, as of December 31, 2018, 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 2,856,575 shares of our common stock with respect to which American Century Investment Management, Inc. had sole voting power with respect to 2,715,018 shares, and sole dispositive power with respect to 2,856,575 shares.

(5) The percent of voting securities owned is based on the number of outstanding shares of our common stock on December 31, 2018.

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HOLDINGS OF OFFICERS AND DIRECTORS

The following table sets forth the number of shares of our common stock beneficially owned as of March 1, 2019, by (1) each director and nominee for director, (2) each of the executive officers named in the Summary Compensation Table for 2018 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)
Arcilia C. Acosta	2,277	1,018	3,295	*
Robert B. Evans	9,630	-	9,630	*
John W. Gibson	267,672	10,362	278,034	*
Tracy E. Hart	719	485	1,204	*
Michael G. Hutchinson	9,330	-	9,330	*
Pattye L. Moore	500	32,945	33,445	*
Pierce H. Norton II	223,628	-	223,628	*
Eduardo A. Rodriguez	8,746	1,331	10,077	*
Douglas H. Yaeger	19,630	-	19,630	*
Curtis L. Dinan	126,430	-	126,430	*
Caron A. Lawhorn	125,117	-	125,117	*
Robert S. McAnnally	14,867	-	14,867	*
Joseph L. McCormick	55,650	-	55,650	*
All directors and executive officers as a group	882,191	46,141	928,332	*

* 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, shares held through our Profit Sharing Plan and shares held through our Employee Stock Purchase Plan. There are no shares issuable pursuant to grants of RSUs or PSUs within 60 days of March 1, 2019.

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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 and our Profit Sharing Plan as of March 1, 2019.

Executive Officer/Director	Stock Held by 401(k) Plan	Stock Held by Profit-Sharing Plan
Robert B. Evans	-	-
John W. Gibson	-	-
Michael G. Hutchinson	-	-
Pattye L. Moore	-	-
Pierce H. Norton II	-	-
Eduardo A. Rodriguez	-	-
Douglas H. Yaeger	-	-
Curtis L. Dinan	5,040	-
Caron A. Lawhorn	1,100	-
Robert S. McAnnally	-	-
Joseph L. McCormick	2,959	-
All directors and executive officers as a group	11,416	-

(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 average of the high and low trading prices 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, 2019.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act, requires our directors, executive officers and beneficial owners of 10 percent or more of our common stock to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of our common stock. Based solely on a review of the copies of reports furnished to us and representations that no other reports were required, we believe that all of our directors, executive officers, and 10 percent or more shareholders during the fiscal year ended December 31, 2018, complied on a timely basis with all applicable filing requirements under Section 16(a) of the Exchange Act, except one Form 4, reporting a purchase of shares by Ms. Acosta, was filed two business days late.

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COMPENSATION DISCUSSION AND ANALYSIS

The Compensation Discussion and Analysis contains a detailed description of our executive compensation philosophy, the elements of compensation that we provide to our NEOs.

Our NEOs for the fiscal year ended December 31, 2018, are as follows:

Name	Title
Pierce H. Norton II	President and Chief Executive Officer
Curtis L. Dinan	Senior Vice President and Chief Financial Officer
Caron A. Lawhorn	Senior Vice President, Commercial
Robert S. McAnnally	Senior Vice President, Operations
Joseph L. McCormick	Senior Vice President, General Counsel and Assistant Secretary

EXECUTIVE SUMMARY

The purpose of the Compensation Discussion and Analysis is to describe the process and analysis that the Executive Compensation Committee uses in making compensation decisions for the NEOs, the components of compensation used and the rationale behind the decisions that were made. Our leadership team is committed to improving business results while providing value to both our customers and stakeholders as reflected in the performance highlights below.

2018 Performance Highlights

- In 2018, we generated net income of $172 million, or $3.25 per diluted share compared with 2017 net income of $163 million, or $3.08 per diluted share. 2018 operating income was $288 million, compared to operating income of $317 million in 2017.
- We paid dividends totaling $1.84 per share, totaling $97 million.
- The market price of our common stock was $79.60 per share at December 31, 2018, an increase of approximately 137 percent from the closing price of $33.63 on February 3, 2014, our first day of “regular way” trading and an increase of 8.7 percent over last year’s closing price of $73.26 at December 29, 2017.
- We generated TSR of approximately 167 percent from February 3, 2014, through December 31, 2018. This return exceeded the returns over the same period of eight of the nine companies in our peer group, the S&P MidCap 400 Index (59.66 percent), the S&P MidCap Utilities Index (57.40 percent) and the Dow Jones Industrial Average (77.26 percent).
- Driving safely, personal injury prevention and public safety continue to be a priority at ONE Gas. We achieved a 7 percent improvement in our DART rate as compared to last year and a 3 percent improvement in our PVIR.

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Our executive compensation programs have features designed to align the interests of executives with stakeholders. The following chart provides an overview of our compensation programs:

What We Do	What We Don't Do
✓ Emphasize a pay-for-performance focus where the majority of executive compensation is performance based	× Enter into employment agreements with executive officers
✓ Grant an annual incentive that is based on financial, operational and individual performance	× Provide excise tax gross-ups upon a CIC
✓ Grant 80 percent of LTI in performance-vesting equity to incent the accomplishment of long-term sustainable business goals while aligning the interests of our executives and stakeholders	× Provide tax gross-ups on other compensation or benefits
✓ Engage an independent executive compensation consultant	× Pay dividends on unearned restricted or performance shares
✓ Maintain a clawback policy to recoup incentive-based compensation awards under certain circumstances	× Encourage excessive or imprudent risk taking
✓ Enforce share ownership guidelines for executives and independent directors to ensure dedication to the company's accomplishment of long-term sustainable business goals and to align the interests of our executives, independent directors and stakeholders	× Offer any perquisites to executive officers
✓ Prohibit executives and independent directors from hedging or pledging activities, subject to an exception for CEO approval pledges described in greater detail below	× Offer incentive programs that have uncapped individual performance or company performance modifiers
✓ Restrict CIC cash benefits to "double-trigger" vesting	× Allow unlimited short-term incentive payouts
✓ Restrict CIC acceleration of equity vesting to "double-trigger" vesting	× Allow hedging or pledging of Company stock
✓ Review tally sheets for NEOs prior to making compensation decisions	

Our Philosophy

We provide executive compensation programs designed to attract, engage, motivate, reward and retain highly effective key 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.

A significant part of each executive's pay is at-risk in the form of performance-based STI and LTI awards. A NEO's compensation package is generally comprised of the following elements:

- Base salary,
- Annual STI cash awards, and
- LTI awards including:
  - PSUs, and
  - RSUs.

We believe that our executive compensation programs provide our executive officers with a balanced pay mix of market-competitive base salaries, STI awards tied to achieving financial and operational targets, and PSU awards promoting long-term sustainable business results by being tied to relative TSR over a three-year performance period.

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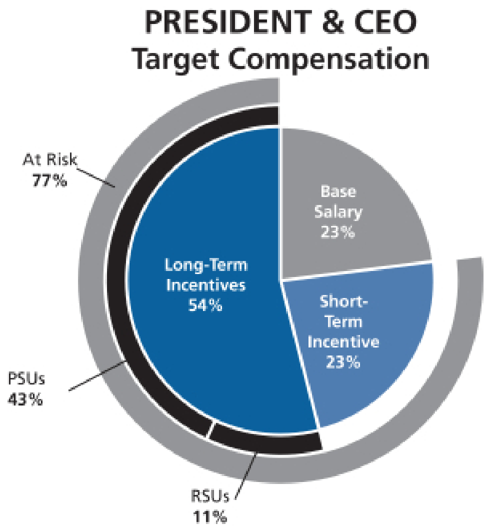
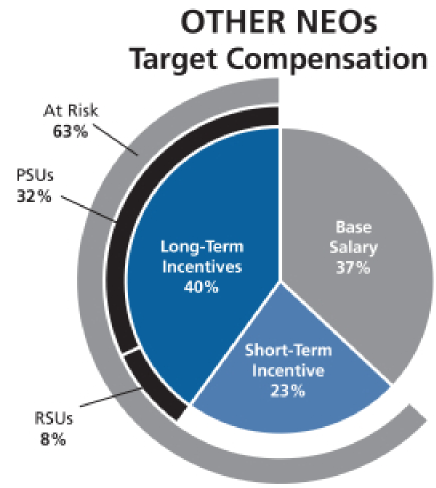
The Committee evaluates compensation data while considering our compensation philosophy in determining the allocation of these elements to NEOs. For 2018, 77 percent of the CEO's total target compensation was "at risk" and an average of 63 percent was "at risk" for the other NEOs.





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 for various reasons, including 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 of Directors

The Committee, which is comprised of independent directors, reviews our executive compensation programs, market benchmark data and the executive officer compensation packages each year. It 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 current year's STI program, including individual target opportunities.

In making individual compensation decisions, the Committee reviews the 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 2018 Shareholder Advisory Vote to Approve 2017 Executive Compensation

In 2018, we received a favorable advisory vote on our executive compensation, with 96.7 percent of the company's shares voting in favor of the executive compensation. 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 engages an independent executive compensation consultant, Meridian, to advise on matters related to executive and non-employee director compensation. This includes assessing the peer group and competitive market data, providing advice 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 2018, the Committee found that Meridian continues to meet the SEC rules and NYSE listing standards for independence.

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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, weighting, targets and the threshold/maximum 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 the end of 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 so that the Committee can consider 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 levels for our executive officers, including the NEOs, using publicly available information from our peer group. The assessment includes information on 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 natural gas utility company; and
- Similar character in areas such as revenue, market capitalization and number of customers.

After considering this criteria and recommendations from both its independent executive compensation consultant and management, the companies listed below were chosen by the Committee to comprise the 2018 peer group. The Committee believes referencing these peers is appropriate when reviewing our executive compensation programs.

Alliant Energy Corporation	Pinnacle West Capital Corporation
Atmos Energy Corporation	PNM Resources Inc.
Avista Corporation	Portland General Electric Company
El Paso Electric Company	South Jersey Industries, Inc.
IDACORP Inc.	Southwest Gas Corporation
New Jersey Resources Corporation	Spire, Inc. (formerly Laclede Group, Inc.)
Northwest Natural Gas Company	Vectren Corporation
Northwestern Corporation	~~WGL Holdings, Inc.~~[1]

1 WGL Holdings, Inc. was eliminated from the peer group upon its acquisition by AltaGas Ltd. on July 6, 2018.

The Committee evaluates the composition of the peer group at least annually and makes appropriate changes, as necessary. For 2018, the benchmarking peer group remains unchanged from the 2017 peer group with the exception of the WGL Holdings, Inc. acquisition.

The Committee assessed the market competitiveness of our NEOs' compensation based on the data provided by its independent executive compensation consultant. This data includes 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 (base salary + target STI);
- Target annualized grant date value of LTI awards; and
- Target total direct compensation (target total cash compensation + LTI awards).

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ELEMENTS OF OUR EXECUTIVE COMPENSATION PROGRAM FOR 2018

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 executives' efforts with the interests of our stakeholders by providing a financial cash incentive tied directly to key measures of the company's financial and operational performance aligned with our long-term strategy. Awards can be modified based on individual performance.	Annual cash compensation, earned based on performance against pre-established goals and individual performance
	RSUs	Promotes the alignment of our executives' interests with those of our stakeholders, supports long-term equity ownership and promotes retention through the service-vesting requirement.	Time-based RSUs that cliff vest in three years
	PSUs	Provides performance incentives to our executives to align their interests and performance with our stakeholders by rewarding sustained share price performance and promotes retention through the service-vesting requirement.	Performance-based stock units that 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, disability or death.	Includes medical, dental, disability, life insurance and accidental death which are generally the same as the broader employee base
	Retirement	Provide for basic retirement needs. Attracts and retains executives.	Can include 401(k), pension plans, NQDC plan, SERPs and/or Profit Sharing

2018 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. For the CEO, the base salary component is equal to his STI target opportunity. 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 approve the following base salaries for 2018:

Name	Base Salary as of January 1, 2017	Base Salary effective January 1, 2018	Dollar Increase	Percentage Increase
Pierce H. Norton	$720,000	$775,000	$ 55,000	8%
Curtis L. Dinan	$435,000	$435,000	$ 0	0%
Caron A. Lawhorn	$360,000	$365,000	$ 5,000	1%
Robert S. McAnnally	$350,000	$365,000	$ 15,000	4%
Joseph L. McCormick	$325,000	$340,000	$ 15,000	

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Salary increases are based on performance and bring base salaries closer to the market positioning identified by the independent executive compensation consultant. The base salary for Mr. Dinan remained the same as 2017 due to market positioning.

Short-Term Incentive

Our 2018 STI awards were based on four measures–one financial measure and three operational measures focused on safety:

Measure	Weighting	Definition
EPS	70%	Based on net income as determined in accordance with generally accepted accounting principles, divided by the daily weighted-average number of common shares outstanding for the year ended December 31, 2018, plus fully vested shares that have not been issued and unvested stock awards granted under our compensation plans, but only to the extent the awards dilute earnings per share.
TRIR	10%	The number of OSHA incidents times 200,000 work hours divided by the sum of actual hours worked.
DART	10%	The sum of OSHA incidents resulting in missed workdays, health-related work restrictions and job transfers times 200,000 work-hours divided by the sum of actual hours worked.
PVIR	10%	The number of preventable vehicle incidents per 1,000,000 miles driven.

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 better 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 one of the company's core values. Safe driving, personal injury prevention, public safety and reducing the severity of injuries are priorities. The Committee reinforces the importance of safety by including three measures in the STI. In addition to these four measures, there is an individual performance modifier ranging from 0–125 percent 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); and
- industry and community leadership.

Each NEO has a target opportunity that is established at the beginning of each performance year. Annually, the Committee reviews the STI target opportunities for each NEO. The STI target opportunity for the CEO was increased to 100 percent of base salary in 2018 to align with market. The other NEOs remained unchanged as compared to 2017.

Name	2018 STI Target Opportunity as a Percentage of Base Salary
Pierce H. Norton II	100%
Curtis L. Dinan	65%
Caron A. Lawhorn	65%
Robert S. McAnnally	65%
Joseph L. McCormick	55%

For 2018, 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.

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Individual awards under our STI plan are calculated using the following formula:

Base Salary earned in 2018	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 2018 meeting, the Committee established the threshold, target and maximum performance goals for the 2018 STI measures. The EPS target was set based on the 2018 strategic and financial plan with consideration given to the company's 2017 EPS performance. For the operational goals, TRIR was set at 7 percent over 2017. The DART target was set at 5 percent improvement from our 2017 performance. The PVIR target was set at a 5 percent improvement over 2017.

	2018 Plan				2018 Actual Results			
Criteria	Threshold (50% of Target)	Target (100% of Target)	Maximum (150% of Target)	Weight	Percentage Payable at Target	Percentage Payable at Maximum	Results at December 31, 2018	Payout Percent Based on December 31, 2018 Results
EPS	$2.89	$3.08	$3.27	70%	70%	105%	$3.25	100.9%
TRIR	1.22	1.11	1.00	10%	10%	15%	1.26	-
DART	0.68	0.44	0.40	10%	10%	15%	0.43	11.3%
PVIR	1.92	1.71	1.62	10%	10%	15%	1.75	9.0%
Company Performance Modifier:								121.2%

For each performance measure in the table above, 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. If our actual results are between the stated performance levels, the percentage payable is interpolated between threshold and target or target and maximum.

The CEO evaluated the 2018 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, if appropriate by the Committee. The Committee, together with the Corporate Governance Committee, evaluates the CEO's performance against his pre-established goals and objectives to determine the individual performance modifier for the CEO. The Committee determined that the CEO had met the 2018 goals and assigned a rating of 100 percent for his individual performance. Individual performance modifiers for the other NEOs ranged from 105 percent to 107 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 2018 plan year that were paid in March 2019:

Name	Base Salary earned in 2018	STI Target Opportunity	Company Performance Modifier	Individual Performance Modifier	STI Award
Pierce H. Norton II	$775,000	100%	121.2%	100%	$939,300
Curtis L. Dinan	$435,000	65%	121.2%	106%	$363,255
Caron A. Lawhorn	$365,000	65%	121.2%	105%	$301,924
Robert S. McAnnally	$365,000	65%	121.2%	105%	$301,924
Joseph L. McCormick	$340,000	55%	121.2%	107%	$242,509

Long-Term Incentives

During 2018, we granted LTI awards to our NEOs under our ECP consisting of PSUs and RSUs. The grants were awarded as 80 percent PSUs and 20 percent RSUs. 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.

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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 2018 Equity Grant*
Pierce H. Norton II	$1,400,007	$349,985	$1,749,992
Curtis L. Dinan	$ 340,032	$ 85,008	$ 425,040
Caron A. Lawhorn	$ 319,990	$ 80,032	$ 400,022
Robert S. McAnnally	$ 319,990	$ 80,032	$ 400,022
Joseph L. McCormick	$ 300,019	$ 74,987	$ 375,003

* Represents the grant date value approved by the Committee. The values displayed in the Summary Compensation Table represent the accounting value of the PSUs.

Based on compensation data reviewed by the Committee, the 2018 LTI awards for Messrs. Norton, Dinan, McAnnally, and McCormick were increased based on performance and to better align with their market positioning for LTI and target total compensation.

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 that 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, NEOs have their accounts credited with an amount equal to all ordinary cash dividends that would have been paid as if shares were issued on the grant date. The dividend equivalents are deemed to be reinvested. If a NEO forfeits any PSUs, 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 and the addition of CenterPoint Energy and Chesapeake Utilities for the 2018 PSU grant. These companies are like ONE Gas in having:

- Notable gas utility operations;
- Similarly sized revenue, market capitalization, assets and number of customers;
- Strong trading correlations with ONE Gas; and
- Similar peer companies.

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The peer group for the 2018 PSUs is as follows:

Alliant Energy Corporation	NiSource, Inc.
Atmos Energy Corporation	Northwest Natural Gas Company
Avista Corporation	NorthWestern Corporation
CenterPoint Energy, Inc.	South Jersey Industries, Inc.
Chesapeake Utilities	Southwest Gas Corporation
CMS Energy Corporation	Spire, Inc. (formerly Laclede Group, Inc.)
New Jersey Resources Corporation	

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 to 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 2015 PSUs

The 2015 PSU grants vested in February 2018. The Committee reviewed the company's relative TSR performance during the performance period against the peer group and has determined that its 77.45 percent TSR result ranks first amongst the nine peer companies. The Committee certified the performance with a corresponding payout of 200 percent of target.

The peer group previously approved by the Committee for this grant includes, after considering certain merger activity which eliminated three companies:

Atmos Energy Corporation	Southwest Gas Corporation
Avista Corporation	Spire, Inc.
New Jersey Resources Corporation	Vectren Corporation
Northwest Natural Gas Company	WGL Holdings, Inc.
South Jersey Industries, 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, 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 three NEOs who are active participants including Mr. Norton, Mr. Dinan, and Ms. Lawhorn.

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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 for employees who are not eligible for the Qualified Pension Plan. The company contributes 1 percent of a participant's annual eligible compensation. The company may also make additional discretionary contributions each year. Eligible compensation is limited to the qualified plan limits. The company contributions and earnings are not taxable until distributed. Only one of our NEOs, Mr. McAnnally, is a participant in this Profit Sharing Plan.

Other Benefits: Our executive officers, including the NEOs, 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, employee stock purchase, 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.

Executives employed at the time that we became a standalone company have five years from January 31, 2014, to satisfy individual share ownership requirements. Executives hired after that date have five years from their start date to satisfy individual share ownership requirements.

Below are the base salary multiples for share ownership for the NEOs:

Name	Title	Multiple of Base Salary
Pierce H. Norton II	President and Chief Executive Officer	6
Curtis L. Dinan	Senior Vice President and Chief Financial Officer	4
Caron A. Lawhorn	Senior Vice President, Commercial	3
Robert S. McAnnally	Senior Vice President, Operations	3
Joseph L. McCormick	Senior Vice President, General Counsel and Assistant Secretary	4

As of December 31, 2018, all NEOs with the exception of Mr. McAnnally, had met their individual share ownership requirements. Mr. McAnnally joined the company in March 2015 and has until March 2020 to meet his individual share ownership requirement.

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 under broad influence across many people	• 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 stock ownership and consistent LTI practices	• Our stock 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 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 61 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.

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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.

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 the policies in 2018.

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.

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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
Arcilia C. Acosta, Member
Robert B. Evans, Member
Tracy E. Hart, Member
Michael G. Hutchinson, Member
Eduardo A. Rodriguez, Member

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NAMED EXECUTIVE OFFICER COMPENSATION

The following table reflects the compensation paid to the NEOs in respect to our 2018 fiscal year.

SUMMARY COMPENSATION TABLE FOR 2018

Name and Principal Position	Year	Salary	Stock Awards(1)	Non-Equity Incentive Plan Compensation(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(3)	All Other Compensation(4)	Total
Pierce H. Norton II	2018	$ 775,000	$ 1,870,544	$ 939,300	$ 540,706	$ 96,780	$ 4,222,330
President and Chief Executive	2017	$ 720,000	$ 1,593,284	$ 838,000	$ 786,270	$ 83,675	$ 4,021,229
Officer	2016	$ 700,000	$ 1,509,792	$ 670,000	$ 882,325	$ 101,856	$ 3,863,973
Curtis L. Dinan	2018	$ 435,000	$ 454,320	$ 363,255	$ -	$ 50,100	$ 1,302,675
Senior Vice President and Chief	2017	$ 435,000	$ 424,663	$ 400,000	$ 694,838	$ 44,795	$ 1,999,296
Financial Officer	2016	$ 435,000	$ 432,493	$ 307,000	$ 452,763	$ 55,056	$ 1,682,312
Caron A. Lawhorn	2018	$ 365,000	$ 427,575	$ 301,924	$ -	$ 41,000	$ 1,135,499
Senior Vice President,	2017	$ 360,000	$ 424,663	$ 305,000	$ 294,511	$ 36,935	$ 1,421,109
Commercial	2016	$ 360,000	$ 432,493	$ 251,000	$ 357,007	$ 45,516	$ 1,446,016
Robert S. McAnnally	2018	$ 365,000	$ 427,575	$ 301,924	$ -	$ 71,213	$ 1,165,712
Senior Vice President, Operations	2017	$ 350,000	$ 371,980	$ 320,000	$ -	$ 63,802	$ 1,105,782
	2016	$ 325,000	$ 350,655	$ 243,000	$ -	$ 50,823	$ 969,478
Joseph L. McCormick	2018	$ 340,000	$ 400,837	$ 242,509	$ 32,832	$ 51,813	$ 1,067,991
Senior Vice President, General	2017	$ 325,000	$ 346,500	$ 260,000	$ 144,141	$ 45,477	$ 1,121,118
Counsel and Assistant Secretary	2016	$ 310,000	$ 324,005	$ 185,000	$ 109,712	$ 37,541	$ 966,258

(1) 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, 2018, included in our Annual Report on Form 10-K filed with the SEC on February 20, 2019.

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	2018	2017	2016
Pierce H. Norton II	$ 3,041,119	$ 2,585,250	$ 2,459,904
Curtis L. Dinan	$ 738,623	$ 689,400	$ 704,660
Caron A. Lawhorn	$ 695,088	$ 689,400	$ 704,660
Robert S. McAnnally	$ 695,088	$ 603,225	$ 570,134
Joseph L. McCormick	$ 651,700	$ 561,861	$ 528,495

(2) Reflects STI awards earned in 2018, 2017 and 2016 and paid in 2019, 2018 and 2017, respectively, under our annual STI plan. For a discussion of the performance criteria established by the Committee for awards under the 2018 annual STI plan, see "2018 Performance and Compensation Decisions—*Short-Term Incentive*" above on page 45.

(3) The amounts reflected represent the aggregate change during 2018 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 2018, the change in pension value reflects the increase due to additional service and pay for the year, offset by a decrease in present value due to the higher discount rate in effect on the measurement date (3.8 percent as of December 31, 2017, and 4.4 percent as of December 29, 2018). The Qualified Pension Plan was closed to new participants as of December 31, 2004. All of our NEOs, with the exception of Mr. McAnnally, participate in the Qualified Pension Plan. The SERP was closed to new participants on January 1, 2014, although no new participants had been added since 2005. Ms. Lawhorn and Messrs. Norton and Dinan participate in the SERP. During 2018, the pension value for Mr. Dinan decreased $3,805. During 2018, the pension value for Ms. Lawhorn decreased $12,373.

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(4) 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, (ii) amounts paid for length of service awards and (iii) the value of shares received in 2018, 2017 and 2016 under our Employee Stock Award Program as of the date of issuance 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)]	ONE Gas Stock Award[(e)]
Pierce H. Norton II	2018	$ 80,280	$ 16,500	$ -	$ -	$ -
	2017	$ 67,200	$ 16,200	$ -	$ -	$ 275
	2016	$ 84,960	$ 15,900	$ -	$ -	$ 996
Curtis L. Dinan	2018	$ 33,600	$ 16,500	$ -	$ -	$ -
	2017	$ 28,320	$ 16,200	$ -	$ -	$ 275
	2016	$ 38,160	$ 15,900	$ -	$ -	$ 996
Caron A. Lawhorn	2018	$ 23,700	$ 16,500	$ -	$ 800	$ -
	2017	$ 20,460	$ 16,200	$ -	$ -	$ 275
	2016	$ 28,620	$ 15,900	$ -	$ -	$ 996
Robert S. McAnnally	2018	$ 38,463	$ 16,500	$ 16,250	$ -	$ -
	2017	$ 34,028	$ 16,200	$ 13,300	$ -	$ 275
	2016	$ 19,278	$ 15,900	$ 14,650	$ -	$ 996
Joseph L. McCormick	2018	$ 34,713	$ 16,500	$ -	$ 600	$ -
	2017	$ 29,003	$ 16,200	$ -	$ -	$ 275
	2016	$ 20,645	$ 15,900	$ -	$ -	$ 996

(a) For additional information on our NQDC Plan, see "Nonqualified Deferred Compensation for 2018" below on page 59.

(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 ONE Gas, Inc. Profit Sharing Plan.

(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 shares awarded under our Employee Stock Award Program or cash service awards.

The NEOs received no other perquisites or other personal benefits from the company in 2018.

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GRANTS OF PLAN-BASED AWARDS FOR 2018

The following table reflects the grants of plan-based awards to the NEOs during 2018.

Grants of Plan-Based Awards

		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)
Name	Grant Date	Threshold	Target	Maximum	Threshold	Target	Maximum		
Pierce H. Norton II									
Restricted Unit	2/19/2018							5,134	$ 349,985
Performance Unit	2/19/2018				10,269	20,537	41,074		$1,520,559
Short-Term Incentive	1/1/2018	$ -	$ 775,000	$ 1,453,125					
Curtis L. Dinan									
Restricted Unit	2/19/2018							1,247	$ 85,008
Performance Unit	2/19/2018				2,494	4,988	9,976		$ 369,312
Short-Term Incentive	1/1/2018	$ -	$ 282,750	$ 530,156					
Caron A. Lawhorn									
Restricted Unit	2/19/2018							1,174	$ 80,032
Performance Unit	2/19/2018				2,347	4,694	9,388		$ 347,544
Short-Term Incentive	1/1/2018	$ -	$ 237,250	$ 444,844					
Robert S. McAnnally									
Restricted Unit	2/19/2018							1,174	$ 80,032
Performance Unit	2/19/2018				2,347	4,694	9,388		$ 347,544
Short-Term Incentive	1/1/2018	$ -	$ 237,250	$ 444,844					
Joseph L. McCormick									
Restricted Unit	2/19/2018							1,100	$ 74,987
Performance Unit	2/19/2018				2,201	4,401	8,802		$ 325,850
Short-Term Incentive	1/1/2018	$ -	$ 187,000	$ 350,625					

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 and DART) 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 2018 under the plan and paid in 2019 are set forth under the "Non-Equity Incentive Plan Compensation" column in the Summary Compensation Table for 2018 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 2018 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.

(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 19, 2018, to February 13, 2021, 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 "2018 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.

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OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END FOR 2018

The following table shows the outstanding equity awards held by the NEOs as of December 31, 2018.

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
Pierce H. Norton II	15,344	$1,221,359	122,647	$9,762,687
Curtis L. Dinan	4,065	$ 323,580	32,521	$2,588,636
Caron A. Lawhorn	3,990	$ 317,625	31,918	$2,540,676
Robert S. McAnnally	3,565	$ 283,737	28,352	$2,256,851
Joseph L. McCormick	3,302	$ 262,894	26,425	$2,103,413

(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

Pierce H. Norton II	5,153	on February 18, 2019
	4,930	on February 15, 2020
	5,261	on February 13, 2021
Curtis L. Dinan	1,476	on February 18, 2019
	1,311	on February 15, 2020
	1,278	on February 13, 2021
Caron A. Lawhorn	1,476	on February 18, 2019
	1,311	on February 15, 2020
	1,203	on February 13, 2021
Robert S. McAnnally	1,208	on February 18, 2019
	1,154	on February 15, 2020
	1,203	on February 13, 2021
Joseph L. McCormick	1,100	on February 18, 2019
	1,075	on February 15, 2020
	1,127	on February 13, 2021

(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 200 percent of the PSUs vesting at the end of the three-year performance period as last year's PSUs paid out at 200 percent.

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The following table reflects the projected vesting level based on our TSR compared with the TSR of the referenced peer group at December 31, 2018:

Performance Unit Vesting Schedule

Pierce H. Norton II	41,226	on February 18, 2019
	39,332	on February 15, 2020
	42,088	on February 13, 2021
Curtis L. Dinan	11,810	on February 18, 2019
	10,489	on February 15, 2020
	10,222	on February 13, 2021
Caron A. Lawhorn	11,810	on February 18, 2019
	10,489	on February 15, 2020
	9,620	on February 13, 2021
Robert S. McAnnally	9,555	on February 18, 2019
	9,177	on February 15, 2020
	9,620	on February 13, 2021
Joseph L. McCormick	8,857	on February 18, 2019
	8,548	on February 15, 2020
	9,019	on February 13, 2021

(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 61.

OPTION EXERCISES AND STOCK VESTED FOR 2018

The following table sets forth stock awards held by the NEOs that vested during 2018. The company has not awarded any options, therefore no NEO exercised any options during 2018, 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)
Pierce H. Norton II	58,511	$ 3,970,852
Curtis L. Dinan	18,705	$ 1,269,431
Caron A. Lawhorn	18,705	$ 1,269,431
Robert S. McAnnally	13,956	$ 947,131
Joseph L. McCormick	14,049	$ 953,443

(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 as follows:

Name	Net Shares Acquired on Vesting	Net Value Realized on Vesting
Pierce H. Norton II	32,539	$2,208,306
Curtis L. Dinan	10,359	$ 703,056
Caron A. Lawhorn	10,352	$ 702,525
Robert S. McAnnally	7,709	$ 523,196
Joseph L. McCormick	7,759	$ 526,658

(2) The value realized on vesting represents the market value of the shares received based on the average of the high and low prices of our common stock on the NYSE on the date of vesting.

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PENSION BENEFITS FOR 2018

The following table sets forth the estimated present value of accumulated benefits as of December 31, 2018, and payments made during 2018, 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
Pierce H. Norton II	Supplemental Executive Retirement Plan	14.08	$ 3,442,287	$ -
	Qualified Pension Plan	14.08	$ 757,627	$ -
Curtis L. Dinan	Supplemental Executive Retirement Plan	15.00(2)	$ 2,326,198	$ -
	Qualified Pension Plan	15.00(2)	$ 590,353	$ -
Caron A. Lawhorn	Supplemental Executive Retirement Plan	20.25	$ 1,333,373	$ -
	Qualified Pension Plan	20.25	$ 1,117,711	$ -
Robert S. McAnnally	Supplemental Executive Retirement Plan	-(3)	$ -	$ -
	Qualified Pension Plan	-(3)	$ -	$ -
Joseph L. McCormick	Supplemental Executive Retirement Plan	-(4)	$ -	$ -
	Qualified Pension Plan	16.00(4)	$ 870,068	$ -

(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, 2018. 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, 2018, included in our Annual Report on Form 10-K filed with the SEC on February 20, 2019.

(2) Mr. Dinan's actual service is 14 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.

(3) Mr. McAnnally is not a participant in the SERP or the Qualified Pension Plan.

(4) Mr. McCormick's actual service is 15 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.

Qualified Pension Plan. The Qualified Pension Plan is a defined benefit pension plan qualified under the Internal Revenue Code. At December 31, 2018, the plan covered non-bargaining unit employees hired prior to January 1, 2005, and certain bargaining-unit employees. Also, at December 31, 2018, 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.

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 2018 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.

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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 2018

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)
Pierce H. Norton II	2018	$ 93,000	$ 80,280	$ (76,114)	$ -	$ 1,326,826
	2017	$ 65,400	$ 67,200	$ 181,351	$ 43,028	$ 1,229,660
	2016	$ 96,860	$ 84,960	$ 72,117	$ 9,260	$ 958,737
Curtis L. Dinan (6)	2018	$ 34,800	$ 938,318	$ 33,965	$ -	$ 20,157,682
(5)	2017	$ 41,360	$ 757,869	$ (1,524,917)	$ -	$ 19,150,599
(4)	2016	$ 62,780	$ 658,049	$ 9,950,101	$ -	$ 19,876,287
Caron A. Lawhorn	2018	$ 54,750	$ 23,700	$ (12,876)	$ 5,279	$ 1,440,763
	2017	$ 166,290	$ 20,460	$ 85,128	$ 5,307	$ 1,380,468
	2016	$ 167,500	$ 28,620	$ 34,509	$ 5,220	$ 1,113,897
Robert S. McAnnally	2018	$ 18,250	$ 38,463	$ 3,283	$ -	$ 224,816
	2017	$ 63,270	$ 34,028	$ 7,654	$ -	$ 164,820
	2016	$ 38,180	$ 19,278	$ 2,410	$ -	$ 59,868
Joseph L. McCormick	2018	$ 94,000	$ 34,713	$ (51,039)	$ -	$ 1,083,936
	2017	$ 126,700	$ 29,003	$ 150,663	$ -	$ 1,006,262
	2016	$ 138,620	$ 20,645	$ 58,861	$ -	$ 699,896

(1) The "All Other Compensation" column of the Summary Compensation Table at page 53 includes these amounts paid under our NQDC Plan as our excess matching contributions with respect to our 401(k) Plan and excess quarterly and annual company contributions, if applicable, with respect to our Profit Sharing Plan.

(2) There were no above-market earnings in 2018, 2017, or 2016.

(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 201,805, 215,182 and 231,081 for 2014, 2015, and 2016, respectively, in ONEOK shares and 49,849, 51,221 and 52,430 for 2014, 2015 and 2016, 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 215,182, 231,081 and 243,227 for 2015, 2016, and 2017, respectively, in ONEOK shares and 51,221, 52,430 and 53,666 for 2015, 2016 and 2017, 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 231,081, 243,227 and 255,985 for 2016, 2017, and 2018, respectively, in ONEOK shares and 52,430, 53,666 and 54,992 for 2016, 2017 and 2018, respectively, in ONE Gas shares.

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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 and our Profit Sharing 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, 2018, the investment return for the investment options for short-term and long-term investment accounts were as follows:

Fund Name	Plan Level Returns
American Beacon Large Cap Value Instl (AADEX)	-11.99%
Carillon Scout Mid Cap I	-9.74%
5-Year Treasury Note Bond Fund (Fixed Rate)	2.25%
Delaware Small Cap Value Instl (DEVIX)	-17.35%
Dodge & Cox International Stock (DODFX)	-17.98%
Federated Government Obligation (GOIXX)	1.70%
Fidelity Balanced K (FBAKX)	-3.94%
JPMorgan Large Cap Growth R6 (JLGMX)	.57%
JPMorgan Small Cap Equity R5 (VSEIX)	-8.83%
PIMCO Total Return Instl (PTTRX)	5.13%
TCW Total Return Bond I (TGLMX)	.80%
Vanguard Institutional Index I (VINIX)	-4.42%
Vanguard PRIMECAP Adm (VPMAX)	-1.94%
Schwab Managed Retirement Tr Fd 2010 V	-2.74%
Schwab Managed Retirement Tr Fd 2015 V	-2.97%
Schwab Managed Retirement Tr Fd 2020 V	-3.51%
Schwab Managed Retirement Tr Fd 2025 V	-4.68%
Schwab Managed Retirement Tr Fd 2030 V	-5.65%
Schwab Managed Retirement Tr Fd 2035 V	-6.52%
Schwab Managed Retirement Tr Fd 2040 V	-7.33%
Schwab Managed Retirement Tr Fd 2045 V	-8.00%
Schwab Managed Retirement Tr Fd 2050 V	-8.37%
Schwab Managed Retirement Tr Fd 2055 V	-8.60%
Schwab Managed Retirement Tr Fd Inc V	-1.76%

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.

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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, Profit Sharing 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.

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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.

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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, 2018, 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, 2018. 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.

Pierce H. Norton II	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	$ 4,650,000
Short-Term Incentive	$ 775,000	$ -	$ 775,000
Health and Welfare Benefits	$ -	$ -	$ 31,142
Equity			
Restricted Unit	$ 743,534	$743,534	$ 1,221,359
Performance Unit	$5,943,217	$ -	$ 4,881,343
Total	$6,686,751	$743,534	$ 6,102,702
Total	$7,461,751	$743,534	$11,558,844

Curtis L. Dinan	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	$ -	$ -	$ 27,609
Equity			
Restricted Unit	$ 203,008	$203,008	$ 323,580
Performance Unit	$1,624,060	$ -	$1,294,318
Total	$1,827,068	$203,008	$1,617,898
Total	$2,109,818	$203,008	$3,363,757

Caron A. Lawhorn	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	$1,204,500
Short-Term Incentive	$ 237,250	$ -	$ 237,250
Health and Welfare Benefits	$ -	$ -	$ 27,609
Equity			
Restricted Unit	$ 201,354	$201,354	$ 317,625
Performance Unit	$1,610,738	$ -	$1,270,338
Total	$1,812,092	$201,354	$1,587,963
Total	$2,049,342	$201,354	$3,057,322

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Robert S. McAnnally	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	$1,204,500
Short-Term Incentive	$ 237,250	$ -	$ 237,250
Health and Welfare Benefits	$ -	$ -	$ 21,575
Equity			
Restricted Unit	$ 173,523	$173,523	$ 283,737
Performance Unit	$1,377,468	$ -	$1,128,425
Total	$1,550,991	$173,523	$1,412,162
Total	$1,788,241	$173,523	$2,875,487

Joseph L. McCormick	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	$1,054,000
Short-Term Incentive	$ 187,000	$ -	$ 187,000
Health and Welfare Benefits	$ -	$ -	$ -
Equity			
Restricted Unit	$ 159,948	$159,948	$ 262,894
Performance Unit	$1,281,117	$ -	$1,051,706
Total	$1,441,065	$159,948	$1,314,600
Total	$1,628,065	$159,948	$2,555,600

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CEO PAY RATIO FOR 2018

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 2018 Proxy Statement as there have been no changes in 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 2018, 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, 2017. Specifically, we used Form W-2 Box 1 compensation minus any compensation received from the vesting of LTIs (i.e., PSU and RSU vestings) in 2018. 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 ($4,222,330) to the median employee's annual total compensation ($88,565). The ratio between the annual total compensation of our CEO to the median of the annual total compensation of all of our employees is 48:1. 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.

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PROPOSAL 3 – ADVISORY VOTE ON EXECUTIVE COMPENSATION

INTRODUCTION

At our 2015 Annual Meeting of Shareholders, a substantial majority of our shareholders voted for an annual say on pay vote. As a result, we intend to provide our shareholders with an annual, non-binding advisory say on pay vote on executive compensation until the next required non-binding advisory vote on the frequency of future advisory say on pay votes as required by the rules of the SEC.

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 50;
- 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 49.

For additional information on the compensation program for our NEOs, including specific information about compensation in fiscal year 2018, please read the "Compensation Discussion and Analysis," along with the subsequent tables and narrative descriptions, beginning on page 40.

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 2019 Annual Meeting of Shareholders pursuant to Item 402 of Regulation S-K, including the Compensation Discussion and Analysis, compensation tables and narrative discussion."

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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 in person 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.

THE 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.

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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.

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ABOUT THE 2019 ANNUAL MEETING

The following questions and answers are provided for your convenience and briefly address some commonly asked questions about our 2019 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 ONE Gas, Inc. of proxies to be voted at our 2019 Annual Meeting of Shareholders and at any adjournment or postponement of the meeting. You are invited to attend our Annual Meeting of Shareholders on May 23, 2019, at 9:00 a.m., Central Daylight Time. The meeting will be held at our company headquarters at ONE Gas, Inc., First Place Tower, 15 E. Fifth Street, 2nd Floor, Tulsa, Oklahoma 74103. For directions to the meeting, please visit our website at www.ONEGas.com.

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 25, 2019, may attend and vote at the meeting. If your shares are held in the name of a broker, bank, or other holder of record, often referred to as being held "in street name," bring a copy of your brokerage account statement or legal proxy, which you may obtain from your broker, bank, or other holder of record of your shares.

Please note: no cameras, recording equipment, large bags, weapons, briefcases or packages will be permitted in the meeting.

Will the annual meeting be webcast?

Our annual meeting also will be webcast on May 23, 2019. You are invited to visit www.ONEGas.com at 9:00 a.m., Central Daylight Time, on May 23, 2019, 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 25, 2019, you have the right to vote the shares of record you held that day in person at the meeting or 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 Employee Stock Purchase Plan, our 401(k) Plan and our Profit Sharing Plan. In addition, these voting methods are available to ONEOK employees who own our shares in the ONEOK, Inc. 401(k) Plan (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 nine 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.proxypush.com/ogs, which is available 24 hours a day, 7 days a week, until 11:59 p.m. (Central Daylight Time) on May 22, 2019.
- 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 22, 2019.
- 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.

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- 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 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 25, 2019, this proxy statement and our 2018 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 in person.

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 2019 annual meeting),

  (b) a shareholder writes comments on a proxy card, or

  (c) a shareholder authorizes disclosure.

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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, our Profit Sharing Plan and the ONEOK Plan voted?

If you hold shares of our common stock through our 401(k) Plan, our Profit Sharing 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, our Profit Sharing Plan and the ONEOK Plan, your voting instructions must be received by May 20, 2019.

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 2019 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 25, 2019, including those shares held in our Direct Stock Purchase and Dividend Reinvestment Plan, our Employee Stock Purchase Plan, our 401(k) Plan, our Profit Sharing 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, our Profit Sharing 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, our Profit Sharing 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. 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 copies, to the extent you request them, for each member of your household who was a registered shareholder as of the record date. You may make this request 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 1-800-468-9716 for assistance. You also may contact EQ Shareowner Services 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.

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 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.

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May I access the notice of annual meeting, proxy statement, 2018 annual report and accompanying documents on the internet?

The notice of annual meeting, proxy statement, 2018 annual report and accompanying documents are currently available on our website at www.ONEGas.com. Additionally, in accordance with rules of the SEC, you may access this proxy statement, our 2018 annual report and any other proxy materials we use at http://shareholder.onegas.com, which does not infringe on the anonymity of a person accessing such website. The website does not employ “cookies” or other user-tracking features.

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.proxypush.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, 470 West Avenue, Stamford, Connecticut 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 2019 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, EQ Shareholder Services, a division of Equiniti Trust Company, 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.

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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 2020 Annual Meeting of Shareholders should be received by our corporate secretary at our principal executive offices no later than December 5, 2019. 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 2020 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 2020 annual meeting, a shareholder's notice must be delivered to, or mailed to and received at, our principal executive offices no later than December 5, 2019.

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 1-800-468-9716 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.

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ANNUAL REPORT ON FORM 10-K

Our 2018 annual report to shareholders (which includes our Annual Report on Form 10-K for the year ended December 31, 2018) is available on our website at www.ONEGas.com. Additionally, and in accordance with the rules of the SEC, you may access our 2018 annual report at http://shareholder.onegas.com, which does not infringe on the anonymity of a person accessing such website. The website does not employ "cookies" or other user-tracking features. 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, 2018. 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

Brian K. Shore
Corporate Secretary

Tulsa, Oklahoma
April 3, 2019

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15 East Fifth Street
Tulsa, OK 74103
www.ONEGas.com

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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 nine director nominees listed below:

1. Election of directors:

	FOR	AGAINST	ABSTAIN		FOR	AGAINST	ABSTAIN
01 Arcilia C. Acosta	☐	☐	☐	06 Pattye L. Moore	☐	☐	☐
02 Robert B. Evans	☐	☐	☐	07 Pierce H. Norton II	☐	☐	☐
03 John W. Gibson	☐	☐	☐	08 Eduardo A. Rodriguez	☐	☐	☐

⇩ *Please fold here – Do not separate* ⇩

04 Tracy E. Hart	☐	☐	☐	09 Douglas H. Yaeger	☐	☐	☐
05 Michael G. Hutchinson	☐	☐	☐				

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, 2019. ☐ 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.

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ONE Gas, Inc.

ANNUAL MEETING OF SHAREHOLDERS

Thursday, May 23, 2019
9:00 a.m. Central Time

15 East Fifth Street
Tulsa, Oklahoma 74103

proxy

ANNUAL MEETING OF SHAREHOLDERS MAY 23, 2019

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 23, 2019, 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, the ONE Gas, Inc. Profit Sharing 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 20, 2019. 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.proxypush.com/ogs

Use the Internet to vote your proxy until 11:59 p.m. (CT) on May 22, 2019.

PHONE
1-866-883-3382

Use a touch-tone telephone to vote your proxy until 11:59 p.m. (CT) on May 22, 2019.

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-10 are Confidential
and will be provided pursuant to the terms of the Protective Agreement.

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF JEFF BRANZ

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

1. "My name is Jeff 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 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.

Jeff Branz

SUBSCRIBED AND SWORN TO BEFORE ME by the said Jeff Branz on this 9 day of December, 2019.

NOTARY SEAL PUBLIC
M. BETH WILLIAMS
Notary Public
State of Oklahoma
Comm. # 13002055 Expires 03/01/21

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

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

CYNDI KING

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF CYNDI KING

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Cyndi King. My business address is 15 East Fifth Street in Tulsa, Oklahoma.

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

A. I am the Director of Treasury and Finance for ONE Gas, Inc. ("ONE Gas"). 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 have a Bachelor of Science degree in Business Administration majoring in Accounting from Oklahoma State University. I have worked for ONE Gas or its predecessor ONEOK, Inc., for 19 years in areas that include Gas Accounting and Treasury. I have been a Certified Treasury Professional since 2014, and I have served on the ONE Gas Benefits Committee, which reviews all pension activity, since 2014.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I provided testimony in the Company's statement of intent filed in June 2017 with the cities in the Rio Grande Valley Service Area and in Gas Utilities Docket ("GUD") Nos. 10739 and 10766 before the Railroad Commission of Texas ("Commission").

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

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Company's request to earn a return on the portion of the contributions to the ONE Gas prepaid pension asset that are attributable to TGS and are part of the rates the Company is seeking approval of in this statement of intent.

II. PENSION FUNDING BACKGROUND

Q. WHAT FINANCIAL ACCOUNTING STANDARD IS APPLICABLE TO PENSION PLAN EXPENSE?

A. The expense associated with a pension plan is determined in accordance with Financial Accounting Standards Board ("FASB") Financial Accounting Standard 87 that is now codified as FASB Accounting Standards Codification Topic 715 ("ASC Topic 715"), Compensation - Retirement Benefits.[1]

Q. ARE ANY OTHER REGULATIONS OR STANDARDS APPLICABLE TO PENSION PLAN EXPENSE?

A. Yes. Pension funding is regulated by the Employee Retirement Income Security Act ("ERISA") and the Pension Protection Act ("PPA").[2] ERISA sets minimum standards for defined-benefit pension plans, including ONE Gas'. The PPA, which was enacted after ERISA, contains the rules used to determine the minimum

[1] https://asc.fasb.org/imageRoot/03/64938803.pdf.

[2] The Pension Protection Act is available at https://www.pbgc.gov/prac/laws-and-regulations/pension-protection-act-of-2006.

required cash contribution and the maximum deductible cash contribution for each year.

Q. HOW WERE PENSION PLANS TYPICALLY FUNDED UNDER ERISA?

A. For pension plan years earlier than 2008, minimum pension funding requirements were specified in ERISA. In general, any projected unfunded liability was designed to be eliminated over a period of 10-15 years, meaning a typical plan would be fully funded after 10-15 years (this assumes no change in relevant variables such as interest rates, investment return, or participant demographics).

Q. DID THE PPA CHANGE FUNDING REQUIREMENTS? IF SO, HOW?

A. Yes, it did. The PPA, which became effective with the 2008 plan year, established new minimum funding requirements for nearly all pension plans. The PPA requires a pension plan sponsor to annually contribute an amount equal to: (1) the benefits estimated to be earned for the current plan year; plus (2) an amount sufficient to reduce any underfunding over a seven-year period. Since the PPA decreased the period for amortizing the unfunded liability, it significantly accelerated the required contributions to satisfy the new funding requirements.

Q. HOW HAS PENSION EXPENSE TYPICALLY BEEN DETERMINED FOR RATEMAKING PURPOSES?

A. For ratemaking purposes, the accrual methodology set forth in ASC Topic 715 is used to calculate pension expense. This is the same methodology required for financial reporting purposes under Generally Accepted Accounting Principles ("GAAP"). ASC Topic 715 requires companies to accrue pension costs over the working life of each qualified employee. An annual calculation is required to determine the amount of pension expense that must be recognized for financial reporting purposes. The calculation considers the accumulated amount that should have been accrued at the present time for each participant, and requires a number of assumptions to be made, including the age at which active employees are likely to retire, the expected future return on pension plan assets, expected future payroll levels, and an appropriate discount rate. In addition, certain gains and losses are amortized over a multi-year period. This amortization helps to mitigate significant fluctuations that can occur from year-to-year in pension plan investment earnings. Thus, the calculation of pension expense is a snapshot at a point in time. It is impacted by what has happened in the past as well as what is expected to happen in the future. In addition, there is a gradual true-up of past estimates with actual results over time.

Q. ARE THE ONE GAS AND TGS PENSIONS STILL OPEN TO NEW PARTICIPANTS?

A. No. The ONE Gas pension plan has been closed to new entrants since 2005 and the TGS pension plan was closed when TGS was acquired. The two plans were merged into one plan in 2016.

III. PRIOR COMMISSION DECISIONS SUPPORT TGS'S REQUEST

Q. HAS THE INCLUSION OF THE COMPANY'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 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 PGBC 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 and 10766 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.

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[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 Area (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, and 10766, 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); and *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 30 (March 20, 2018).

IV. ONE GAS' APPROACH TO FUNDING ITS PENSION OBLIGATIONS

Q. HOW IS A PREPAID PENSION ASSET CREATED?

A. The difference between total cumulative contributions made to the pension trust and the cumulative ASC Topic 715 expense recognized at a point in time equals either a prepaid pension asset (historically, because contributions have exceeded ASC Topic 715 expense) or an accrued pension liability (historically, because ASC Topic 715 expense recognized has exceeded contributions).

While a plan may not be fully funded, it is still possible for a company to fund an amount more than what it has expensed. In ONE Gas' case, it has funded more than it has expensed. If at any point in time a prepaid pension asset exists, then it means that cumulative cash contributions to the plan exceed cumulative ASC Topic 715 pension expense.

Additionally, IRS minimum required contributions, as spelled out by the PPA, and ASC Topic 715 expense are not the same and are not designed to be the same. ASC Topic 715 expense is leveled out over the life of the benefit. However, IRS required minimum payments (i.e., contributions) are leveled over a seven-year period. This difference is what leads to the prepaid pension asset on which TGS is seeking to earn a return, consistent with the Commission's prior decisions in prior TGS cases.

Q. HOW DOES ONE GAS DETERMINE HOW MUCH IS REQUIRED TO BE CONTRIBUTED TO ITS PENSION PLAN EACH YEAR?

A. ONE Gas relies on third-party actuaries to calculate the level of funding required under the PPA. As required by the PPA, ONE Gas contributes an annual amount at least equal to: (1) the benefits expected to be earned by plan participants in the coming year; plus (2) one-seventh of the underfunded balance. Once the plan becomes fully funded, the required contribution becomes simply the benefits expected to be earned in the coming year. In some previous years, ONE Gas has found advantages to fund more than this amount which include lower pension expense, lower variable-rate Pension Benefit Guarantee Committee ("PBGC") premiums and income tax reductions.

Q. DOES ONE GAS HAVE A TARGETED FUNDING PERCENTAGE?

A. Yes, ONE Gas does have a targeted funding percentage. At a minimum, ONE Gas targets the plan funding to ensure plan assets equal approximately 80% of the plan's liability on a GAAP basis (in accordance with ASC Topic 715) and at least 80% on a IRS funding basis (as calculated under the PPA).

Q. WHAT IS THE RATIONALE BEHIND THIS PERCENTAGE?

A. A target of 80% is prudent because failure to fund at least 80% of the plan's liability on an IRS funding basis may result in benefit limitations, prohibition of lump sum payment to retirees, cessation of benefit accruals and restrictions on plan amendments. Specifically, under the PPA, a plan may become subject to various benefit limitations if its Adjusted Funding Target Attainment Percentage ("AFTAP") falls below certain thresholds. Certain financial and actuarial information (i.e., a "4010 filing") must be provided to the PBGC if the Funding Target Attainment Percentage ("FTAP") is less than 80% on a IRS funding basis. At-risk status for determining minimum required contributions is defined in the PPA.

Q. WHEN IS A PPA PLAN CONSIDERED TO BE AT RISK?

A. A plan is in at-risk status for the plan year under review if the plan's FTAP for the preceding plan year was less than 80% of liabilities on an IRS funding basis and the plan's FTAP measured using certain "at-risk assumptions" is less than 70% of liabilities on a IRS funding basis.

Q. WHAT HAPPENS WHEN A PLAN'S STATUS DROPS TO AT-RISK?

A. The overall cost of the plan increases. When a plan's status drops to at-risk, the plan is subject to higher minimum contribution requirements based on mandated actuarial assumption changes. Specifically, participants eligible to retire within the next 11 years must be assumed to retire immediately when first eligible and all participants must be assumed to elect the most valuable form of payment available when they begin receiving benefits. The net effect of the assumptions and expense adjustments is to increase contribution and PBGC variable-rate premiums.

Q. WHAT AMOUNTS THAT ARE ATTRIBUTABLE TO TGS WERE CONTRIBUTED TO THE PENSION PLAN?

A. ONE Gas' pension plan assets, liabilities, contributions and payments are tracked in four distinct categories: (1) TGS, (2) Oklahoma Natural Gas, (3) Kansas Gas Service, and (4) Corporate. Contributions made to the Corporate category are allocated to the three divisions. Amounts contributed to the pension plan for which TGS is responsible are listed below as included in Exhibit CLK-1.

Contributions attributable to TGS pension plan

	TGS Portion of Corporate Contribution	Direct TGS Contribution	TGS Total
2009	$14,731,220	$8,097,644	$22,828,864
2010	$17,698,110	$3,781,762	$21,479,872
2011	$12,154,900	$2,855,836	$15,010,736
2012	$18,548,704	$4,719,691	$23,268,395
2013	$0	$0	$0
2014	$0	$0	$0
2015	$0	$0	$0
2016	$0	$0	$0
2017	$6,171,808	$21,395,091	$27,566,899
2018	$8,083,440	$8,700,000	$16,783,440
2019	$0	$0	$0

Q. WHAT ACTIONS ARE TAKEN TO ENSURE THAT THE PENSION IS NOT OVERFUNDED WHILE ALSO ATTEMPTING TO REDUCE FUTURE VOLATILITY?

A. ONE Gas has undertaken a Liability Driven Investment Strategy ("LDIS") with a glide path to obtain a less volatile investment objective. The glide path simply moves more of the assets into fixed income with maturities that match plan liabilities as the plan becomes better funded, thus reducing risk to the plan. This will result in the plan assets moving in tandem with the liability as interest rates rise and fall, creating less volatility and less fluctuation in the annual expense. The value of a LDIS is the assurance that assets are not over-exposed to equity markets that could require ONE Gas and/or customers to make large future fundings.

V. RETURN ON THE FUNDS ONE GAS HAS COMMITTED TO ITS PENSION OBLIGATIONS

Q. WHY DO YOU BELIEVE TGS SHOULD RECEIVE A RETURN ON ITS PORTION OF THE PREPAID PENSION ASSET?

A. I believe a return is warranted because it: (1) is consistent with the Commission's treatment in GUD No. 10506, which I addressed previously; (2) is consistent with traditional rate-making principles; (3) encourages ONE Gas to ensure adequate funding of its pension obligations, which is a prudent practice; and (4) encourages ONE Gas to continue to minimize future expenses for customers.

Q. HOW IS ALLOWING TGS A RETURN ON THE PREPAID PENSION ASSET CONSISTENT WITH TRADITIONAL RATEMAKING PRINCIPLES?

A. To receive full recovery of an investment, (a cash outlay that is expensed over a number of years), TGS must recover both the expense and the cost of capital associated with the investment which, in this case, is the prepaid pension asset.

Changes in federal funding requirements (through the PPA), coupled with financial market downturns, which have an inverse relationship to plan liabilities, have significantly increased the amount of required contributions to the ONE Gas pension plan and have accelerated the timing of such required payments. The investment ONE Gas is required to make in the safety of its pension obligations is no different than the investment it must make in the safety of its physical assets and the return on that investment should be no different.

Q. HOW WAS THE PREPAID PENSION ASSET FUNDED?

A. The prepaid pension asset is the amount of cash ONE Gas has contributed to the plan that is more than expense; therefore, the cost of the asset has not been collected from customers and has been funded solely by ONE Gas through cash on hand, which was replaced with long-term debt and equity.

Q. IS IT REASONABLE TO FUND PENSION OBLIGATIONS IN A MANNER THAT MAY CREATE A PREPAID PENSION ASSET?

A. Yes, it is. Funding the pension obligations in a manner that creates a prepaid pension asset is reasonable because it avoids the negative (and costly) consequences of underfunding the plan and putting the plan into an at-risk status, either intentionally or inadvertently, through failure to build sufficient cushion into actuarially determined estimates. Absent the prepaid pension asset, the plan would be further underfunded increasing future pension expense and related costs such as the variable-rate PBGC premium which for plan year 2019 is calculated as a 4.3% of unfunded vested benefits. Funding in this manner increases the likelihood that funds will be available to pay the promised benefits, while earning returns on the asset that reduce pension expense. Each additional dollar of contribution reduces pension expense by an amount equal to the expected return on the additional contribution. If the proposed Central-Gulf Service Area ("CGSA") prepaid asset of $23.3 million did not exist, pension expense for the following year would increase by $1.7 million using the expected pension earnings rate of 7.2% ($23.3 million times 7.2%).

Q. HOW HAVE OTHER JURISDICTIONS TREATED PREPAID PENSION ASSETS?

A. Utilities in several states have been allowed to earn a return on the prepaid pension assets, including the District of Columbia, Michigan, New York, Ohio, Oklahoma, and Texas. In an Oregon Public Utility Commission Pension Survey, 16 commissions reported that they recognize a "Prepaid Pension Asset/Liability" through allowing "a return on amount invested in asset."[5] An additional three commissions reported that they include cash contributions in "Working Capital," and six other commissions used a "Combination of Methods." Of those using multiple methods, several commissions mentioned including pension costs in rate base, or otherwise allowing the utility to earn a return on the asset.

Q. WHAT ARE THE TGS AND PROPOSED CGSA PORTIONS OF THE PREPAID PENSION ASSET AS OF THE END OF THE TEST YEAR?

A. TGS has a total prepaid asset as of June 30, 2019, of $34.9 million and an allocated portion of the corporate prepaid asset of $15.3 million. TGS's portion of the total asset is $50.2 million, and the proposed CGSA portion is $23,340,745. These amounts are shown on Exhibit CLK-2

[5] Oregon Public Utility Commission Pension Survey, Pension Treatment in Rate Making Survey, Summary Report, (Mar. 28, 2013) included in my workpapers.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF INCLUDING THE PREPAID PENSION ASSET IN RATE BASE, AND WHAT IS THE IMPACT THIS FUNDING HAS ON CURRENT EXPENSE?

A. The revenue requirement impact of including the prepaid pension asset in rate base is approximately $1.8 million calculated as follows and as shown in Exhibit CLK-3:

Revenue requirement

		Texas Gas Service		Proposed CGSA
Prepaid Pension Asset	$	50,202,599	$	23,340,745
Less Deferred Taxes		(10,542,546)		(4,901,556)
Rate Base	$	39,660,053	$	18,439,188
Pre-Tax Rate of Return		9.57%		9.578%
Impact to Revenue Requirement	$	3,798,640	$	1,766,105

While including the prepaid pension asset in rate base increases the revenue requirement by $1.8 million as discussed below, it also has the impact of reducing current year expense by $3.6 million for TGS and $1.7 million for the proposed CGSA. These calculations are also shown in Exhibit CLK-3.

Q. HOW HAS THE FUNDING STRATEGY USED BY ONE GAS PROVIDED A BENEFIT TO TGS'S CUSTOMERS?

A. Pension expense is lower due to the funding strategy ONE Gas uses. Test year expense is $5.6 million for TGS and $2,584,326 for the proposed CGSA. However, if the prepaid pension asset did not exist, TGS's plan assets would be $50.2 million less, and ASC Topic 715 pension expense would be $3.6 million higher for TGS and $1.7 million higher for the proposed CGSA. Therefore, the 2019 ASC Topic

715 pension expense for TGS and the proposed CGSA is $3.6 million and $1.7 million less, respectively, because of ONE Gas' funding strategy. The savings of $3.6 million in pension expense are calculated by taking the PPA asset multiplied by the expected return of 7.2%, which is the same expected return used for the calculation of pension expense.

Additionally, a reduced level of funding would result in an increase in expense related to the PBGC variable-rate premium. Had ONE Gas not made the contributions that created the prepaid pension asset, the plan would be significantly less funded, which would cause an increase in the PBGC variable premiums. Therefore, ONE Gas' approach is not only good for the plan but also minimizes long-term costs for all stakeholders.

Q. HOW MUCH HAVE TEXAS CUSTOMERS BENEFITED SINCE THE PREPAID PENSION ASSET STARTED ACCUMULATING?

A. As shown on Exhibit CLK-3 the cumulative benefit for TGS's customers since December 2008 has been $34 million and $15.8 million for the proposed CGSA. The benefit experienced during the test year is the $3.6 million I discussed earlier for TGS and $1.7 million for the proposed CGSA.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR POSITION ON THE INCLUSION OF THE PREPAID PENSION ASSET IN RATE BASE.

A. The Commission's treatment of the prepaid pension asset in GUD No. 10506 should be followed in this statement of intent. In addition, the prepaid asset was created from an investment by ONE Gas, just as ONE Gas would invest in a pipeline. Accordingly, in line with traditional rate-making principles, TGS should be allowed to earn the full rate of return because ONE Gas' capital (both debt and equity) was used to create the asset. Moreover, customers are benefiting from the prepaid pension asset by having a reduced expense.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

TEXAS GAS SERVICE COMPANY
CENTRAL GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019

PENSION CONTRIBUTIONS
($ in 000s)

	A	B	C	D	E	F	G
10–11	**LINE NO.**	**Year**	**Corporate Contribution**	**TGS Distrigas %**	**TGS Portion of Corporate Contribution**	**Direct TGS Contribution**	**TGS Total**
12		(a)	(b)	(c)	(d)	(e)	(f)
13	1	2009	$ 77,126.804	19.10%	$ 14,731.220	$ 8,097.644	$ 22,828.864
14	2	2010	$ 95,100.000	18.61%	$ 17,698.110	$ 3,781.762	$ 21,479.872
15	3	2011	$ 61,700.000	19.70%	$ 12,154.900	$ 2,855.836	$ 15,010.736
16	4	2012	$ 90,880.472	20.41%	$ 18,548.704	$ 4,719.691	$ 23,268.395
17	5	2013	$ -	21.39%	$ -	$ -	$ -
18	6	2014	$ -	23.08%	$ -		$ -
19	7	2015	$ -	23.43%	$ -		$ -
20	7	2016	$ -	23.70%	$ -	$ -	$ -
21	8	2017	$ 24,764.201	24.92%	$ 6,171.808	$ 21,395.091	$ 27,566.899
22	9	2018	$ 32,700.000	24.72%	$ 8,083.440	$ 8,700.000	$ 16,783.440
23	10	2019	$ -	25.01%	$ -	$ -	$ -

TEXAS GAS SERVICE COMPANY
CENTRAL GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019

Allocation of Prepaid Pension Asset
($ in 0s)

Line No.	Year	Corporate	Corporate Allocation	TGS Direct	Total TGS	CGSA Total
	(a)	(b)	(c) = b * distrigas TGS %	(d)	(e) = c + d	(f) = e * CGSA %
1	as of December 31, 2017	$ 37,948,363	$ 9,490,886	$ 32,425,224	$ 41,916,110	$ 19,488,099
2	2018 Expense	$ (6,775,664)	$ (1,694,594)	$ (4,371,937)	$ (6,066,531)	$ (2,820,518)
3	2018 Contributions	$ 32,700,000	$ 8,178,270	$ 8,700,000	$ 16,878,270	$ 7,847,231
4	as of December 31, 2018	$ 63,872,699	$ 15,974,562	$ 36,753,287	$ 52,727,849	$ 24,514,812
5	Jan-Jun 2019 Expense	$ (2,500,000)	$ (625,250)	$ (1,900,000)	$ (2,525,250)	$ (1,174,067)
6	Jan-Jun 2019 Contributions	$ -	$ -	$ -	$ -	$ -
7	as of June 30, 2019	$ 61,372,699	$ 15,349,312	$ 34,853,287	$ 50,202,599	$ 23,340,745
8						
9	test year expense	$ (5,887,832)	$ (1,472,547)	$ (4,085,969)	$ (5,558,515)	$ (2,584,326)
10						
11	distrigas TGS %:	25.01%				
12	CGSA %:	46.4931%				

TEXAS GAS SERVICE COMPANY
CENTRAL GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019

PREPAID PENSION ASSET
($ in 000s)

Line No.	Year	Corporate Prepaid Pension Asset	Distrigas %	Corporate Allocation	TGS Direct Prepaid Pension Asset	Total TGS Prepaid Asset Balance	Pension Earnings Rate	TGS Expense Reduction	Cumulative TGS Expense Reduction	CGSA Expense Reduction	Cumulative CGSA Expense Reduction
	(a)	(b)	(c)	(d) = b * c	(e)	(f) = d + e	(g)	(h) = f * g	(i)	(j)	(k)
1	2009	$ 76,202.403	19.10%	$ 14,554.659	$ 19,480.004	$ 34,034.663	8.50%	2,892.946	2,892.946	1,345.020	1,345.020
2	2010	$ 100,780.939	18.61%	$ 18,755.333	$ 23,753.167	$ 42,508.500	8.50%	3,613.222	6,506.169	1,679.899	3,024.920
3	2011	$ 113,615.032	19.70%	$ 22,382.161	$ 26,441.982	$ 48,824.143	8.50%	4,150.052	10,656.221	1,929.488	4,954.407
4	2012	$ 128,912.542	20.41%	$ 26,311.050	$ 28,089.017	$ 54,400.067	8.50%	4,624.006	15,280.227	2,149.844	7,104.251
5	2013	$ 23,487.283	21.39%	$ 5,023.930	$ 26,116.391	$ 31,140.321	8.00%	2,491.226	17,771.452	1,158.248	8,262.499
6	2014	$ 22,729.077	23.08%	$ 5,245.871	$ 24,061.965	$ 29,307.836	7.75%	2,271.357	20,042.810	1,056.024	9,318.524
7	2015	$ 20,408.490	23.43%	$ 4,781.709	$ 18,123.346	$ 22,905.055	7.75%	1,775.142	21,817.951	825.318	10,143.842
7	2016	$ 17,613.089	23.70%	$ 4,174.478	$ 15,640.946	$ 19,815.424	7.75%	1,535.695	23,353.647	713.992	10,857.834
8	2017	$ 37,948.363	24.92%	$ 9,457.605	$ 32,425.224	$ 41,882.829	7.75%	3,245.919	26,599.566	1,509.128	12,366.963
9	2018	$ 63,872.699	24.72%	$ 15,789.331	$ 36,753.287	$ 52,542.618	7.25%	3,809.340	30,408.906	1,771.080	14,138.043
10	Jan-June 2019	$ 61,372.699	25.01%	$ 15,349.312	$ 34,853.287	$ 50,202.599	7.20%	3,614.587	34,023.493	1,680.534	15,818.577
11								Allocation			
12							TGS Total	to service area	CGSA		
13					Prepaid Pension Asset		$ 50,202.599	46.4931%	$ 23,340.745		
14					Less Deferred Taxes (21%)		(10,542.546)		(4,901.556)		
15					Rate Base		$ 39,660.053		$ 18,439.188		
16					Pre Tax Rate of Return		9.578%		9.578%		
17					Impact to Rates		$ 3,798.640		$ 1,766.105		
18											
19											

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF CYNDI KING

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

1. "My name is Cyndi King. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Director of Treasury and Finance 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.

Cyndi King
Cyndi King

SUBSCRIBED AND SWORN TO BEFORE ME by the said Cyndi King on this ____ day of 12/3, 2019.

AUTUMN EDDINGS
NOTARY PUBLIC - STATE OF OKLAHOMA
Commision # 16011697
My Commission Expires December 19, 2020

Autumn Eddings
Notary Public in and for the State of Oklahoma

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

MARK W. SMITH

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

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LIST OF EXHIBITS

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 for its proposed Central-Gulf Service Area.

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. 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 31 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 in Gas Utilities Docket ("GUD") Nos. 10506, 10526, 10739 and 10766 in Texas.

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 Confidential Exhibit MWS-1 which summarizes the Utility Insurance Company ("UIC") insurance expense charged to TGS and the change in direct insurance cost inclusive of lower deductible limits. Attached as Exhibit MWS-2 is a document showing the Oklahoma Insurance Commission's ("OIC's") approval of UIC's original rates and approving UIC as an approved and regulated insurance company. Confidential Exhibits MWS-3, MWS-4, MWS-5, and MWS-6 are the policies issued by UIC to TGS. Confidential Exhibit MWS-7 is the feasibility study that was filed with the OIC.

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

A. Yes, they were.

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 Texas Utilities Code. In addition to my testimony addressing UIC, Company witness Stacey L. McTaggart also addresses the affiliate cost recovery standard, and Company witnesses Anthony Brown and Mindy R. Edwards sponsor the schedule that identifies the amount of Corporate insurance premium costs TGS is seeking to recover through rates.

II. ONE GAS' INSURANCE AND RISK MANAGEMENT PROGRAM

Q. WHAT IS A CAPTIVE INSURANCE COMPANY?

A. A captive or captive insurance company is a company 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 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. In the Company's experience, the retail market 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 pushed for a $5 million deductible. These high levels of deductibles result in the company and the customers being exposed to significant financial losses because they must incur large claims prior to deductibles being met. 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 spikes 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 should result in more favorable rates over the long-term.

Q. PLEASE BRIEFLY DESCRIBE UIC AND HOW IT FITS INTO 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 OIC, 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. Captives can also write third party risks but currently UIC is responsible for the risks of ONE Gas and its operating divisions only.

In addition to providing management services for the daily operations of UIC, Aon provides ONE Gas with consultation services regarding insurable risks, coverage, actuarial and other related services. However, 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 OIC has oversight and governs the rates and capitalization of UIC. Attached as Exhibit MWS-2 is a document approving UIC's original rates and approving UIC as an insurance company. UIC's initial annual filing along with its audited annual financials have been filed with the OIC and have been accepted.

Q. HAVE THE PREMIUMS FROM UIC BEEN ACCEPTED IN RATES IN OTHER JURISDICTIONS?

Yes, they have been accepted as appropriate costs in Oklahoma, Kansas, and Texas. Specifically, UIC costs were included in the GUD Nos. 10739 and 10766.

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 as if it is a division, its own appropriate premium based on its asset and risks. This Corporate insurance expense is allocated through Distrigas to each division, including TGS, as described by Mr. Brown.

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; and

4) automobile liability.

Copies of these policies are attached as Confidential Exhibit MWS-3 through Confidential Exhibit MWS-6.

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 $250,000 deductible per occurrence for each type of policy listed above. This $250,000 deductible is much lower than what is commercially available in the retail insurance markets for companies the size of ONE Gas, because, liability insurance (Item 2 above) could not be purchased in the retail marketplace with a deductible below $1 million. In fact, during our November 2018 renewal of the liability coverage, we requested from third-party insurers a rate for coverage from $250,000 to $2 million and received informal quotes at a premium rate of $1.4 million. In our November 2019 renewal, we requested the same information and a verbal quote was given for $3.6 million. In contrast, UIC is able to offer liability insurance coverage from $250,000 to $2 million for $946,000 to ONE Gas Corporate and its three divisions. This results in an annual savings of $2.7 million.

Q. YOU STATED THAT UIC PROVIDES INSURANCE COVERAGE THAT IS NOT COMMERCIALLY AVAILABLE AT THE UIC DEDUCTIBLE LEVEL AND UIC 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 property insurance (Item 1 above), we ask our broker to request quotes for a $250,000 deductible, and only two of the three carriers were willing to quote at this deductible level. Moreover, while one carrier was willing to agree to a rate that would result in a program cost of $710,000, we could not obtain coverage from the carrier because it refused to quote a fee for this coverage. On the other hand, UIC was able to offer this coverage to ONE Gas corporate and its three divisions at a total of $545,000, a savings of $165,000.

Q. EXPLAIN HOW THE COST OF OBTAINING INSURANCE COVERAGE FOR TGS AND ITS PEER DIVISIONS THROUGH UIC IS 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 its peer 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 Aon. 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 for:

1) property insurance, the replacement value of the assets being insured and the potential business interruption or net margins of the division;

2) workers' compensation, the salary and number of employees in a division;

3) automotive insurance, the number of vehicles that each division is operating; and

4) liability insurance, 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, and Aon 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 OIC for their review and approval. I have attached Confidential Exhibit MWS-7, which is the original application filed with the OIC. Any amount of reinsurance that UIC purchases is allocated at cost based on the annual premiums being charged for that type of coverage.

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 the inevitable insurance cycles. Further, having a relatively stable premium rate allows the utility to plan with greater certainty the investment necessary to ensure a safe and reliable system.

Q. HOW ARE THE CHARGES TO TGS FROM UIC DETERMINED?

A. The actual amount of the premium charged is based on different factors such as property replacement values, employee count, net margins, the number of autos, and loss history for each division, and will vary depending on the type of coverage. UIC uses actuarial services of Aon to develop risk-based premiums as previously explained. If a division's property replacement values are greater than that of another utility division, then the division with the greater amount will bear more of the total premium cost charged by UIC. This is also the case for losses. If the loss history is greater in one division, that division will bear a larger premium. ONE Gas believes this is important as it prevents one division from subsidizing another division which may have higher losses. Specifically, Aon provides a quantification of the potential exposure under the various risks by producing a forecast for the upcoming policy year. The analysis is based on ONE Gas and its divisions' own loss experience with actuarial adjustments to account for the nature of the claims, development of claims, underlying loss cost trends and changes in exposure. This risk-based approach more appropriately allocates the cost to each of ONE Gas' divisions and corporate office than a simple rate multiplied by a headcount or rate multiplied by an asset value.

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. In the future, UIC may add risks such as medical stop loss, employee life insurance, and employee medical insurance, but only for our employees. There are no plans to insure third parties outside of ONE Gas, its divisions and subsidiaries and their dependents/families.

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 the company 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. Mr. Brown and

Ms. Mindy Edwards sponsor the schedule that shows the amount of corporate costs for ONE Gas assets that TGS is seeking to recover through rates.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Exhibit MWS-1 is Confidential
and will be provided pursuant to the terms of the Protective Agreement.

GOVERNOR
MARY FALLIN

INSURANCE COMMISSIONER
JOHN D. DOAK

OKLAHOMA INSURANCE DEPARTMENT
STATE OF OKLAHOMA

October 26, 2017

BILL MOURELATOS
76 ST PAUL ST STE 500
BURLINGTON, VT 05401

Re: Approved License
Utility Insurance Company, Inc., OK License #502253624

Dear Mr. Mourelatos:

My staff and I welcome the above referenced company into the State of Oklahoma. Enclosed please find the company's Certificate of Authority as an authorized Pure Captive.

If you are ever in Oklahoma City, we invite you to come into our offices to get acquainted.

Sincerely,

John D. Doak
Insurance Commissioner

Oklahoma License #: 502253624

NAIC #:

State of Oklahoma

Oklahoma Insurance
3625 NW 56th Street, Suite 100
Oklahoma City, Oklahoma 73112

Whereas, the **UTILITY INSURANCE COMPANY, INC.**, a company organized under the laws of **Oklahoma** and located at 15 E FIFTH ST, TULSA, OK, 74103, having complied with the applicable laws of Oklahoma, is hereby licensed and authorized to transact the business of:

Casualty (including vehicle)

Property

This Certificate of Authority shall be perpetual and automatically renewed as of March 1st of every year, unless the company fails to qualify for renewal pursuant to the requirements of Title 36 of the Oklahoma Insurance Code.

IN TESTIMONY WHEREOF, I have hereunto set my Hand and affixed the Official Seal of the Insurance Commissioner at the City of Oklahoma City, State of Oklahoma, this 24th day of October, 2017.

John D. Doak

John D. Doak
Insurance Commissioner
State of Oklahoma Insurance Department

Exhibits MWS-3 through MWS-7 are Confidential
and will be provided pursuant to the terms of the Protective Agreement.

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 this 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 Smith on this 6th day of December, 2019.

JOANNE C. DAVIS
NOTARY
05009895
EXP. 10/25/21
PUBLIC
STATE OF OKLAHOMA

Joanne C Davis

Notary Public in and for the State of Oklahoma

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

JEFFREY J. HUSEN

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

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LIST OF EXHIBITS

DIRECT TESTIMONY OF JEFFREY J. HUSEN

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am a 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 20 years, I have worked in accounting and financial reporting roles. Prior to my current position, I was Assistant Controller - Corporate Accounting and Reporting where I was responsible for corporate accounting, SEC reporting, Sarbanes Oxley and enterprise risk management processes for ONEOK, Inc., ("ONEOK") and ONEOK Partners. 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 PREPARED BY YOU OR UNDER YOUR DIRECTION?

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 and 10766 and before the Kansas Corporation Commission in 18-KGSG-560-RTS.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the aspects of the Tax Cuts and Jobs Act of 2017 (the "Act") that affect TGS. In addition, I explain the Company's calculation of Excess Accumulated Deferred Income Tax ("EDIT").[1]

Q. HOW DOES YOUR TESTIMONY RELATE TO THE TESTIMONY OF OTHER COMPANY WITNESSES?

A. Company witness Stacey L. McTaggart addresses TGS's compliance with the Accounting Order issued by the Commission in GUD No. 10695, and the Company's proposal for returning EDIT to customers. Company witness Janet M. Simpson addresses the calculation of Accumulated Deferred Income Taxes ("ADIT") in her testimony, and Company witness Gracie Guerra sponsors the

[1] https://www.congress.gov/115/bills/hr1/BILLS-115hr1enr.pdf.

schedule that provides the amount of federal income tax expense TGS seeks to recover through rates.

II. THE TAX CUTS AND JOBS ACT OF 2017

Q. HAS THE COMMISSION ADDRESSED THE EFFECT OF TAX REFORM ON TEXAS UTILITIES AND THEIR CUSTOMERS?

A. Yes. In response to the Act, the Commission issued an Accounting Order in GUD No. 10695 on February 27, 2018, that reflects the Commission's directives regarding changes to utility rates to account for the change in the federal corporate tax rate.[2] The Accounting Order includes two specific requirements related to the treatment of EDIT, which I address in my testimony. 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). Ms. McTaggart explains other requirements of the Accounting Order in her testimony and explains the Company's proposal to return EDIT to customers.

Q. DOES THE REVENUE REQUIREMENT IN THIS STATEMENT OF INTENT REFLECT THE NEW CORPORATE TAX RATE?

A. Yes. This is addressed in my testimony and the testimonies of Ms. McTaggart, Ms. Guerra, and Ms. Simpson.

[2] On March 20, 2018, the Commission issued an Order Nunc Pro Tunc in GUD No. 10695, correcting a clerical error in the original Accounting Order.

III. EXCESS ADIT

Q. PLEASE EXPLAIN EDIT.

A. As Ms. Simpson describes in her testimony, ADIT reflects the cumulative timing differences between Income Tax Expense recorded pursuant to accounting principles generally accepted in the United States ("GAAP") for financial reporting purposes and actual income taxes paid to taxing authorities. The Company then applies the tax rate at which it expects the cumulative timing differences to reverse, which rates are typically the current enacted federal and state tax rates (if applicable), to the cumulative timing difference balance to determine the amount of ADIT to record. After a change in the income tax rate is enacted, GAAP requires a company to remeasure the ADIT balance on its books to reflect the new tax rate at which it expects the related timing differences to reverse. EDIT is the difference between the ADIT balance on the day before the tax rate change was enacted and the ADIT balance calculated using the newly enacted corporate tax rate. For regulated public utilities, Accounting Standards Codification ("ASC") 980-740-25[3] requires that a regulatory asset or liability be recorded for the resulting re-measurement of ADIT if it is probable that the excess will be collected from customers or returned to customers through future rates. Ms. McTaggart addresses in her testimony that the Company proposes to treat this excess deferred liability as a separate bill credit outside of base rates to allow for easier tracking of the item and ensure 100% of the EDIT is returned to customers.

[3] https://asc.fasb.org/section&trid=2156937#d3e54046-110423.

Q. DOES THE EDIT REGULATORY LIABILITY INCLUDE ANY ASSOCIATED GROSS UP IN TAXES?

A. No. The Company has not included a gross up of the regulatory liability because the regulatory liability is a refund obligation to customers and not a reduction of future revenues. If the regulatory liability were treated as a reduction of future revenues, ASC 980-740-25 would require the regulatory liability to be grossed-up for the income tax effect of the increase or decrease in future revenues. The gross-up regulatory asset or liability associated with EDIT would itself be considered a temporary tax timing difference for which a deferred tax asset or liability would be recognized. Because the gross-up regulatory liability would generate an offsetting deferred tax asset, recording a tax gross-up associated with the EDIT regulatory liability has no effect on rate base. Because the EDIT liability is a refund obligation and not a reduction of future revenues, the Company has not included an associated gross up nor the corresponding deferred tax asset in rate base. Rate base reflects only the remeasured deferred taxes using the current enacted federal tax rate and the related regulatory liability resulting from remeasurement.

Q. WHAT IS THE AMOUNT OF EDIT FOR TGS?

A. The amount of EDIT is $28,460,166, as shown on Exhibit JMS-2, provided with Ms. Simpson's direct testimony. Exhibit JMS-2 calculates the effect of the change in the statutory federal tax rate on the ADIT of TGS at December 31, 2017 and reflects all adjustments resulting from ONE Gas filing its 2017 federal tax return.

Q. PLEASE DESCRIBE PROTECTED AND UNPROTECTED EDIT.

A. With the implementation of tax reform in 1986, the term "protected EDIT" was adopted to refer to EDIT balances that were described in Section 203(e) of the Tax

Reform Act of 1986 ("TRA 1986").[4] Pursuant to Section 203(e), federal method/life depreciation differences are protected EDIT under the TRA 1986. In addition, any ADIT balances attributable to net operating loss carryforwards are considered to be the result of the federal method/life depreciation differences and those balances are also protected EDIT. There are other items in Section 203(e) that are protected in addition to federal method/life depreciation differences, however, neither the Company, nor ONE Gas, has any of the other categories of protected EDIT. "Unprotected EDIT" referred to all other balances.

Q. PLEASE DESCRIBE THE TREATMENT OF EDIT UNDER TRA 1986.

A. The TRA 1986 allowed the reduction to the excess tax reserve under Section 203(e) to occur no more rapidly than the rate under the average rate assumption method ("ARAM").

Q. WHAT IS ARAM?

A. ARAM is a methodology that annually reduces the excess tax reserve over the remaining regulatory lives of the property that gave rise to the reserve for deferred taxes during the years in which the deferred tax reserve related to such property is reversing. Under this method, the excess tax reserve is annually reduced as the timing differences reverse over the remaining lives of the assets that existed at the date the excess tax reserve was measured.

Q. DOES THE ACT PROVIDE FOR COMPARABLE TREATMENT?

A. Yes. A similar provision is included in the Act at Section 13001(d). To maintain a normalization method of accounting, the Act requires that the utility reduce its

[4] https://www.congress.gov/bill/99th-congress/house-bill/3838.

protected excess tax reserve no faster than it would be reduced under ARAM. It also allows for use of another alternative method if the utility does not have the data needed for ARAM. The Company has the data needed for ARAM, so the alternative method is not applicable.

Q. IS THE COMPANY'S PROPOSAL TO USE ARAM CONSISTENT WITH THE COMMISSION'S ACCOUNTING ORDER ADDRESSING EDIT?

A. Yes. Ordering Paragraph 7 requires the amortization of the EDIT regulatory liability to be calculated using a methodology under the Act, and ARAM is a methodology set forth under the Act.

Q. WHAT TGS AND ONE GAS ITEMS ARE PROTECTED UNDER THE NORMALIZATION RULES?

A. The EDIT attributable to federal method/life depreciation differences are protected. All other EDIT amounts are unprotected under the normalization rules.

Q. WHAT WOULD HAPPEN IF TGS OR ONE GAS VIOLATED NORMALIZATION RULES?

A. The penalties associated with a normalization violation can be very punitive. ONE Gas and the Company could lose the ability to utilize accelerated depreciation. Furthermore, the Act calls for an additional penalty that would be assessed for the amount by which the excess tax reserve was reduced more rapidly than was allowed using a normalized method of accounting. These penalties would be severely detrimental to both the Company and the Company's customers and would significantly increase the cost of service. For instance, the loss of accelerated depreciation would result in the loss of a significant tax deduction that allow companies making significant capital investments to defer income tax liabilities until future periods. The lost tax deduction or any associated tax penalties increases the current cash needs of the company to pay income taxes and can result in incremental borrowings to finance capital expenditure programs or the company's operations. The increased borrowings would result in higher financing costs and ultimately increase the cost of service to ratepayers.

Q. HOW DOES THE COMPANY PROPOSE TO TREAT UNPROTECTED EDIT?

A. TGS proposes to amortize the unprotected EDIT over a ten-year period consistent with the Final Orders issued in GUD Nos. 10739 and 10766.

Q. WHAT AMOUNT OF EDIT WILL BE REFUNDED TO TGS'S CUSTOMERS IN 2020?

A. Exhibit JJH-1 shows the calculation of the amortization amount using the ARAM methodology and the ten-year amortization period for unprotected EDIT. In 2020, $1,286,160 will be credited to customers if the Company's proposal is approved. The calculation in Exhibit JJH-1 utilizes the EDIT balance calculated in Exhibit JMS-2 and an ARAM amortization percentage derived from the Company's fixed asset accounting system that tracks the tax and financial reporting balances and depreciation for the Company and ONE Gas Corporate property plant and equipment.

Q. IS THE COMPANY PROVIDING A SCHEDULE OF REFUNDS TO BE MADE IN FUTURE PERIODS?

A. No. It is not possible to provide the estimated amortization amounts over the remaining regulatory lives of the protected EDIT using the ARAM methodology because it would require the Company to know when assets will be replaced or abandoned in the future. Any estimate of future amounts would have to assume that all assets that existed will be used for their full remaining regulatory lives, and that is not a reasonable assumption. The refund amounts in future periods could change as the Company's property, plant and equipment at December 31, 2017, is retired or replaced, which would impact the timing of the amount of ARAM amortization that is refunded in the future. As these assets are retired or replaced, the timing of the amortization of the EDIT will change in a given year; however, the total amount to be refunded will not change over the life of the assets. Ms. McTaggart explains in her testimony how the Company will provide the annual ARAM amounts in the annual Rate Schedule EDIT-RIDER filing.

Q. HOW DOES THE COMPANY INTEND TO REFUND THIS LIABILITY BACK TO CUSTOMERS?

A. As amounts are identified by the ARAM calculation for refund within a given year, the Company intends to identify those amounts and the associated customer bill credits consistent with the terms of proposed Rate Schedule EDIT-RIDER, which Ms. McTaggart addresses. The Company also intends that the amount of the EDIT credit be applied as an annual one-time bill credit as reflected in Rate Schedule EDIT-RIDER. The Company intends to return this excess deferred liability as a separate bill credit outside of base rates to ensure 100% of the EDIT is returned to customers.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED THE COMPANY'S PROPOSED TREATMENT OF EDIT?

A. Yes, in GUD Nos. 10739 and 10766, the Commission approved the same treatment of EDIT that the Company proposes here.[5]

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[5] *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 45 (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 at FoF 43 (Feb. 5, 2019).

Texas Gas Service Company, a Division of ONE Gas, Inc.
CGSA ISOS RTCS TYE June 30, 2019
Updated for Known and Measurable Changes Through September 30, 2019

ARAM Estimate for amounts attributed TO the Central/Gulf Coast SERVICE AREA
9.30.2019

Estimated Accumulated Deferred Income Taxes for:	Excess ADIT	Protected	Unprotected	TGS Amortization Amount	ONE Gas Amortization Amount	2018 Amortization
Gulf Coast Service Area Plant Assets Depreciation	(33,964,349)	(33,964,349)		(33,964,349)		290,226
Gulf Coast Service Area Repairs	(10,622,000)		(10,622,000)	(10,622,000)		999,021
Gulf Coast Service Area Other Rate Base Items	(3,136,047)		(3,136,047)	(3,136,047)		313,605
TGS Division Plant Assets Depreciation	(264,573)	(264,573)		(264,573)		65,467
ONEGAS Plant Assets Depreciation	(1,542,000)	(1,542,000)			(1,542,000)	183,881
Gulf Coast Service Area NOL	21,068,802	21,068,802		21,068,802		(566,040)
ADFIT - Accumulated Deferred Federal Income Taxes	(28,460,167)	(14,702,120)	(13,758,047)	(26,918,167)	(1,542,000)	1,286,160

Percent Protected 52%

CGSA without Grossup

	TGS Amortization	ONE Gas Amortization	TGS NOL	OGS NOL	Total Amortization
Year 1 - 2018 Actuals	$ 1,668,319	$ 183,881	$ (566,040)	$ 566,040	$ 1,286,160

Texas Gas Service Company, a Division of ONE Gas, Inc.
CGSA ISOS RTCS TYE June 30, 2019
Updated for Known and Measurable Changes Through September 30, 2019

ARAM Estimate for amounts attributed TO the CTX SERVICE AREA
For case filed with Year Ended 9.30.2019

Accumulated Deferred Income Taxes for:	Excess ADIT	Protected	Unprotected	TGS Amortization Amount	ONE Gas Amortization Amount	2018 Amortization
Central Texas Direct Plant Assets Depreciation	(28,694,365)	$ (28,694,365)		$ (28,694,365)		$ 263,234
Central Texas Direct Plant Repairs	(8,319,002)		(8,319,002)	$ (8,319,002)		751,462
Central Texas Other Rate Base Items	(2,676,419)		(2,676,419)	$ (2,676,419)		267,642
TGS Division Plant Assets Depreciation	(225,312)	(225,312)		(225,312)		$ 55,752
ONEGas Plant Assets Depreciation	(1,308,791)	(1,308,791)			$ (1,308,791)	$ 157,735
Central Texas NOL (See NOL tab, Note 6)	19,296,333	19,296,333	-	19,296,333		(499,204)
		$ -		$ -		
ADIT - Accumulated Deferred Income Taxes	(21,927,556)	(10,932,135)	(10,995,421)	(20,618,765)	(1,308,791)	996,621
Percent Protected		50%				

CTX without Grossup

	TGS Amortization	ONE Gas Amortization	TGS NOL	OGS NOL	Total Amortization
Year 1 - 2018 Actuals	$ 1,338,090	$ 157,735	$ (499,204)	$ 499,204	$ 996,621

Texas Gas Service Company, a Division of ONE Gas, Inc.
CGSA ISOS RTCS TYE June 30, 2019
Updated for Known and Measurable Changes Through September 30, 2019

ARAM Estimate for amounts attributed TO the Gulf Coast SERVICE AREA
9.30.2019

Estimated Accumulated Deferred Income Taxes for:	Excess ADIT	Protected	Unprotected	TGS Amortization Amount	ONE Gas Amortization Amount	2018 Amortization
Gulf Coast Service Area Plant Assets Depreciation	(5,269,984)	(5,269,984)		(5,269,984)		26,992
Gulf Coast Service Area Repairs	(2,302,998)		(2,302,998)	(2,302,998)		247,559
Gulf Coast Service Area Other Rate Base Items	(459,628)		(459,628)	(459,628)		45,963
TGS Division Plant Assets Depreciation	(39,261)	(39,261)		(39,261)		9,715
ONEGAS Plant Assets Depreciation	(233,209)	(233,209)			(233,209)	26,146
Gulf Coast Service Area NOL	1,772,469	1,772,469		1,772,469		(66,836)
ADFIT - Accumulated Deferred Federal Income Taxes	(6,532,611)	(3,769,985)	(2,762,626)	(6,299,402)	(233,209)	289,538
Percent Protected		58%				

GCSA

	TGS Amortization	ONE Gas Amortization	TGS NOL	OGS NOL	Total Amortization
Year 1 - 2018 Actuals	$ 330,229	$ 26,146	$ (66,836)	$ 66,836	$ 289,538

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 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.

Jeffrey J. Husen

SUBSCRIBED AND SWORN TO BEFORE ME by the said Jeffrey J. Husen on this 10th day of December, 2019.

Stephanie McClanahan
Notary Public in and for the State of Oklahoma

STEPHANIE MCCLANAHAN
Notary Public, State of Oklahoma
Commission # 00015049
My Commission Expires October 13, 2020

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

JANET M. SIMPSON

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF JANET M. SIMPSON

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Janet M. Simpson. My business address is 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 Vice President of Dively Energy Services Company ("DESC"). DESC is a consulting firm specializing in regulatory accounting and utility ratemaking (DESC is not a CPA firm).

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. 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. 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 Public Utility Commission of Texas, the Railroad Commission of Texas ("Commission"), the Missouri Public Service Commission, and the Massachusetts Department of Public Utilities. A copy of my resume identifying the various docketed proceedings in which I have testified is attached to my testimony as Exhibit JMS-1.

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

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents the Texas Gas Service Company ("TGS" or the "Company"), a division of ONE Gas, Inc. ("ONE Gas") Accumulated Deferred Income Tax ("ADIT") and Excess ADIT amounts that are applicable when determining rates in the Company's proposed Central-Gulf Service Area ("CGSA"). The CGSA combines the Company's existing Central Texas Service Area ("CTSA"), Gulf Coast Service Area ("GCSA") and the City of Beaumont, Texas. The cost of service for customers in the City of Beaumont, Texas is included in and a part of the GCSA. Total CGSA ADIT is a liability of $51,961,390, and Excess ADIT is a liability of $28,460,166, resulting in a combined rate base reduction of $80,421,556. Excess ADIT exists as a result of the reduction in the federal corporate income tax rate pursuant to the Tax Cuts and Jobs Act of 2017 (the "Act"), which was effective January 1, 2018. The sum of total ADIT and Excess ADIT balances are reflected as reductions to rate base on the CGSA Rate

Case Schedules, Schedule B, line 12 and are itemized on Schedule B-9. On a stand-alone basis, the CTSA ADIT is a liability of $40,097,517, and Excess ADIT is a liability of $21,927,556, resulting in a combined rate base reduction of $62,025,073. On a stand-alone basis, the GCSA ADIT is a liability of $11,863,874, and Excess ADIT is a liability of $6,532,611, resulting in a combined rate base reduction of $18,396,483. These ADIT and Excess ADIT amounts are reflected on Schedule B, line 12 and itemized on Schedule B-9 of the CTSA and GCSA Rate Case Schedules.

In addition, the Commission issued an Accounting Order containing requirements for utilities related to the effects the Act on utility rates. Company witness Stacey L. McTaggart addresses the requirements of the Accounting Order, and Company witness Jeffrey J. Husen explains the reversal of Excess ADIT, and Company witness Gracie Guerra describes the calculation of federal income tax at the new rate.

II. <u>BACKGROUND</u>

Q. PLEASE DEFINE ACCUMULATED DEFERRED INCOME TAXES.

A. ADIT are amounts that are recorded on the balance sheet of a company to capture and accumulate the difference between income tax expense calculated on the company’s financial statement and income tax expense calculated for tax return purposes. An ADIT liability is recognized for temporary differences that will result in taxable amounts in future years, while an ADIT asset is recognized for temporary differences that will result in deductible amounts in future years. The differences between financial statement and tax return taxable income that result in the creation of ADIT represent temporary differences in taxable income rather than permanent differences. Over time, the same total amount of expense or revenue will be reflected in taxable income per Book and per Tax, but the year(s) in which the expense or revenue is recognized will differ. The ADIT balance represents the cumulative net amount of those deferred tax liabilities and assets at a given point in time.

Q. WHAT IS THE MAJOR SOURCE OF ADIT FOR TGS?

A. The primary source of ADIT for TGS, and utility companies in general, is the difference in depreciation rates and methods used on a company's financial statement (i.e., "per Book") and the depreciation rates and methods authorized by the Internal Revenue Service ("IRS") for use on the income tax return (i.e., "per Tax"). Generally speaking, the IRS depreciation rates and methods are accelerated as compared to the financial statement and rate case depreciation rates and methods. That means that plant assets are typically depreciated more rapidly per Tax than per Book. As a result, for any particular "vintage" (i.e., calendar year) of plant additions, higher levels of depreciation expense will be deducted on the tax return in early years and lower amounts will be deducted in later years of that asset's life as compared to the depreciation expense recorded per Books. 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 under-depreciated tax basis at that time. For example, if at the time of its retirement, the tax basis accumulated depreciation was $600 relating to 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 under-depreciated 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 the net cost of removal per Book 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 liability, 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 property, plant and equipment per Book as compared the amounts per Tax and/or differences in the balance of accumulated depreciation per Book as compared to the amounts per Tax. 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., gross property, plant and equipment per Book minus accumulated depreciation per Book) and Tax Net Plant (i.e., gross property, plant and equipment per Tax minus accumulated depreciation per Tax). As explained above, typically for utility companies, that calculation yields a net ADIT liability, 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 had sufficient taxable income to make use of all 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 the resulting 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 yet actually 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 liability that is recorded on the balance sheet. 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. TAX CUTS AND JOBS ACT OF 2017

Q. WHAT IS THE TAX CUTS AND JOBS ACT OF 2017?

A. On December 22, 2017, the Act was signed into law. Among other changes, as of January 1, 2018, the Act reduces the corporate federal income tax rate to 21% from 35%.

Q. WHAT IS THE IMPACT OF THE ACT ON THE PROPOSED CGSA ADIT BALANCE IN THIS CASE?

A. Prior to December 22, 2017, the cumulative timing differences underlying the ADIT balance were valued at the then-current statutory income tax rate of 35%. The decrease in the tax rate pursuant to the Act, resulted in the Company owing income tax to the IRS at only 21% when those timing differences reverse. As of December 31, 2017, the portion of that balance that is equal to the underlying timing differences multiplied by 14% (35% minus 21%) represents "Excess ADIT." The Company has not yet amortized and returned to customers the

December 31, 2017, balance of Excess ADIT because this is the first general rate case for either the CTSA or the GCSA since the effective date of the Act. As a result, the entire December 31, 2017 Excess ADIT balances relating to the existing CTSA and GCSA still represent cost free capital appropriate for deduction from rate base in this case. I am presenting the ADIT balance and the Excess ADIT balance separately on Schedule B-9. Ms. McTaggart and Mr. Husen address the impact of the Act as it pertains to the refund of Excess ADIT in this case.

IV. CALCULATION OF THE CGSA ADIT BALANCE

Q. WHAT ARE THE COMPONENTS OF THE PROPOSED CGSA ADIT AMOUNT?

A. The proposed CGSA ADIT balance, inclusive of Excess ADIT consists of the following five major components:

	ADIT at 21%	Excess ADIT	Total
CGSA Direct Plant-Related	(79,896,725)	(44,586,349)	(124,483,074)
CGSA Other Direct Rate Base Items	(5,420,956)	(3,136,047)	(8,557,003)
TGS Division Plant-Related	(58,273)	(264,573)	(322,846)
ONE Gas Plant-Related	(2,766,140)	(1,542,000)	(4,308,140)
CGSA NOL	36,180,704	21,068,803	57,249,507
Total CGSA ADIT	**(51,961,390)**	**(28,460,166)**	**(80,421,556)**

Detailed calculations of each component of ADIT at 21% are discussed below and shown on Exhibit JMS-2. The Excess ADIT column above represents the comparable balances of each category of ADIT as of December 31, 2017, valued at 14% as explained in the previous Section III.

Q. PLEASE EXPLAIN HOW YOU CALCULATED ADIT RELATING TO THE PROPOSED CGSA DIRECT PLANT ASSETS.

A. The first component of total CGSA ADIT is ADIT associated with the plant-related timing differences for plant that is physically located in the proposed CGSA (i.e., "direct plant"). I first computed ADIT applicable to CGSA plant items as of June 30, 2019 by comparing per Book net plant for those locations as of June 30, 2019 to per Tax net plant for those locations as of June 30, 2019, and then updated that comparison of per book amounts to September 30, 2019, consistent with the Company's adjustments to Plant and Reserves. The difference between these two amounts, multiplied by the current income tax rate of 21%, represents the proposed CGSA direct plant-related ADIT as of September 30, 2019. Total CGSA plant-related ADIT as of September 30, 2019 equals ($79,896,725).

Q. PLEASE EXPLAIN THE SECOND COMPONENT OF CGSA ADIT THAT PERTAINS TO OTHER RATE BASE ITEMS.

A. There are several other items that the Company is including in rate base in this case for which there is a difference in the book and tax treatment, specifically:

- Rule 8.209 Regulatory Asset - Distribution Integrity Management Program ("DIMP") Deferral;
- Pension & Financial Accounting Standards ("FAS") 106 Regulatory Asset Deferral; and
- Prepaid Pension Asset

Both the Rule 8.209 deferrals and the Pension and FAS 106 Regulatory Assets deferrals 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 have been 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 of 21%.

The third item is an additional layer of temporary difference that pertains to the book/tax treatment of pension costs. For tax purposes, the amount deducted in any given 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 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. Thus, the reversal of the item identified above as "Pension/ FAS 106 Regulatory Asset 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. Then, the third item reflects the additional temporary difference that arises because actual deduction for tax purposes is equal to the amount by which the pension plan is funded. The sum of these three temporary differences multiplied by the tax rate of 21% represents the CGSA Other Direct Rate Base-related ADIT as of September 30, 2019, which is equal to ($5,420,956).

Q. PLEASE DESCRIBE THE NEXT TWO COMPONENTS OF THE ADIT CALCULATION.

A. The next two components of the CGSA ADIT calculation are for (1) ADIT related to an allocated portion of TGS Division plant, and (2) an allocated portion of ONE Gas Corporate plant as of test-year end. These amounts were computed by comparing net book plant and net tax plant balances for TGS Division and ONE Gas Corporate plant as of June 30, 2019 and, as with respect to direct plant, adjusting those amounts to September 30, 2019. The ONE Gas temporary differences were multiplied by the allocation factors that have been applied to the related plant amounts by Company witness Mindy R. Edwards 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 proposed CGSA. To allocate the appropriate portions to the proposed CGSA, both the TGS Division and the allocated ONE Gas Corporate ADIT amounts were multiplied by the CGSA test-year-end customer allocation factor, consistent with the methodology used by Ms. Mindy Edwards to allocate shared service and corporate expenses and plant and accumulated depreciation balances. The result is ($58,273) of TGS Division plant ADIT and ($2,766,140) of ONE Gas corporate plant ADIT applicable to the proposed CGSA.

Q. WHAT IS THE FINAL COMPONENT OF CGSA ADIT?

A. The final component is ADIT relating to the proposed CGSA's portion of the TGS NOL.

Q. WHY IS ADIT RELATING TO THE TAX NOL 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 June 30, 2019, 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 liability 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 liability balance has the effect of increasing rate base.

Q. WHAT IS THE TOTAL ESTIMATED TGS NOL ADIT APPLICABLE TO THE PROPOSED CGSA AS OF SEPTEMBER 30, 2019, AND HOW IS IT COMPUTED?

A. The total estimated NOL ADIT applicable to the proposed CGSA as a separate jurisdiction as of September 30, 2019 is $36,180,705. The calculation of this amount starts with cumulative 2003 through September 30, 2019 total TGS taxable income per Book of $414,915,273. 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 rate-making adjustments and tax adjustments to determine the CGSA NOL. First, an adjustment was made to align the purchased gas cost expense reflected in the proposed CGSA and other TGS jurisdiction cost centers to equal the jurisdictional purchased gas revenue. Next, I removed amounts that are not applicable for rate-making 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. I also removed parking expenses, which are no longer deductible for tax purposes as a result of the Act. Next, tax deductions were reflected pertaining to the Rule 8.209 Regulatory Asset - DIMP Deferral and Pension and FAS 106 Regulatory Asset Deferral 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 next amounts reflected for tax purposes associated with recognition of plant-related adjustments for tax purposes including tax depreciation, cost of removal expense, retirement losses, and repairs adjustment, net of CIAC amounts that are treated as taxable income. Because the actual tax depreciation expense that is reflected on the Company's tax returns includes the impact of the Company's acquisition adjustment that arose from the 2004 acquisition of the TGS assets from SUCo, the tax depreciation used in the rate-making NOL ADIT calculation referenced above was recalculated excluding the impact of the acquisition adjustment. The final step was to apply the CGSA customer-based allocation factors to the resulting allocable TGS division net loss and the allocable regional net loss amounts as shown on Exhibit JMS-2, page 2. The allocated amounts applicable to the proposed CGSA were then added to the proposed CGSA direct amounts to determine the total CGSA tax NOL.

Q. WHAT IS THE RESULTING CGSA NOL ADIT AMOUNT?

A. The result is a cumulative CGSA Tax NOL of $172,289,069 as of September 30, 2019. Multiplying this amount by the income tax rate of 21% yields the CGSA NOL ADIT of $36,180,705, which is the final component of the CGSA ADIT calculation.

Q. IS INCLUSION OF ADIT ON THE NOL CONSISTENT WITH THE COMMISSION'S PAST TREATMENT OF THIS ISSUE?

A. Yes. The Company's treatment of the NOL in this case is consistent with the Commission's Final Order in Gas Utilities Docket ("GUD") No. 10170 in which the Commission approved an increase in rate base for the ADIT associated with Atmos' NOL, as calculated on a jurisdictional stand-alone basis. As in that case, the driving force behind the Company's NOL position is the substantial plant-related tax deductions associated with its regulated operations. Because these deductions created the ADIT liability that is deducted from rate base, inclusion of the NOL ADIT asset "matches the ADIT liabilities to the ADIT NOL asset created by those deductions," which is what the Commission concluded GUD No. 10170. 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, and 10766. GUD Nos. 10488, 10526, 10656, 10739, and 10766 were resolved through unanimous settlement agreements the Commission approved on May 3, 2016, November 15, 2016, March 20, 2018, November 13, 2018, and February 5, 2019, respectively. 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, 2016.

Q. DOES YOUR ADIT CALCULATION INCLUDE THE IMPACT OF ADIT PERTAINING TO THE KNOWN AND MEASURABLE POST TEST YEAR ADJUSTMENTS TO PLANT THAT ARE REFLECTED IN THE COMPANY'S FILED SCHEDULES?

A. Yes. As noted above, adjustments were made to be consistent with the adjustments proposed by the Company to reflect Plant and Accumulated Depreciation changes through September 30, 2019 as well as to reflect other miscellaneous Plant and Accumulated Depreciation adjustments proposed by the Company. The Company will make a true-up adjustment to ADIT to exclude any plant that is not used and useful as of December 31, 2019, and will provide December 31, 2019 Plant in Service, construction completed not classified, and Accumulated Reserve balances by February 14, 2020.

V. CALCULATION OF THE CTSA AND GCSA ADIT BALANCES

Q. DID YOU FOLLOW THE SAME APPROACH WHEN SEPARATELY CALCULATING THE ADIT AMOUNTS FOR THE CTSA AND GCSA?

A. Yes, the same methodology was used for the CTSA and GCSA calculations as was used for the combined CGSA calculation except that direct service area amounts specifically applicable to the CTSA and GCSA were used rather than total CGSA amounts, and the CTSA and GCSA 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 CTSA ADIT.

A. The amount of ADIT, inclusive of excess ADIT, applicable to the CTSA that should be deducted from rate base if it is necessary to develop a CTSA stand-alone revenue requirement is ($62,025,073) and consists of the following components:

	ADIT at 21%	Excess ADIT	Total
CTSA Direct Plant-Related	(67,915,870)	(37,013,367)	(104,929,237)
CTSA Other Direct Rate Base Items	(4,680,500)	(2,676,419)	(7,356,919)
TGS Division Plant-Related	(49,842)	(225,312)	(275,154)
ONE Gas Plant-Related	(2,365,913)	(1,308,791)	(3,674,704)
CTSA NOL	34,914,608	19,296,333	54,210,914
Total CTSA ADIT	**(40,097,517)**	**(21,927,556)**	**(62,025,073)**

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS PERTAINING TO THE GCSA ADIT.

A. The amount of ADIT, inclusive of excess ADIT, applicable to the GCSA that should be deducted from rate base if it is necessary to develop a GCSA stand-alone revenue requirement is ($18,396,483) and consists of the following components:

	ADIT at 21%	Excess ADIT	Total
GCSA Direct Plant-Related	(11,980,855)	(7,572,983)	(19,553,837)
GCSA Other Direct Rate Base Items	(740,456)	(459,628)	(1,200,084)
TGS Division Plant-Related	(8,431)	(39,261)	(47,692)
ONE Gas Plant-Related	(400,227)	(233,209)	(633,436)
GCSA NOL	1,266,097	1,772,469	3,038,566
Total GCSA ADIT	**(11,863,873)**	**(6,532,611)**	**(18,396,483)**

Q. DOES THE SUM OF YOUR RECOMMENDED CTSA AND GCSA ADIT AMOUNTS EQUAL YOUR RECOMMENDED CGSA ADIT?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

JANET M. SIMPSON, CPA, CR.FA

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PROFILE

Janet Simpson is Vice President of Dively Energy Services Company, LLC, a consulting firm providing accounting and regulatory services to the utility industry. She is also 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 thirty-five 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. As a forensic professional, 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.

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

- BBA in Accounting, University of Texas at Austin
- Certified Public Accountant, Texas
- Certified Forensic Accountant

PROFESSIONAL ASSOCIATIONS

- American Institute of Certified Public Accountants
- Texas Society of Certified Public Accountants
- American College of Forensic Examiners

SELECTED ENGAGEMENTS

- *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 CENTRAL GULF SERVICE AREA
For General Rate Case - Test Year Ended 9/30/2019

Row	Estimated Accumulated Deferred Income Taxes for:	ADIT at 21%	Unamortized Excess ADIT - Bal at 9/30/2019	Total CGSA ADIT and Excess ADIT at 9/30/2019
8	**Central Gulf Service Area Plant Assets Depreciation**	(61,333,789)	(33,964,349)	(95,298,138)
9	**Central Gulf Service Area Direct Plant Repairs**	(18,562,936)	(10,622,000)	(29,184,936)
10	**Subtotal CGSA Direct Plant Assets Depreciation**	(79,896,725.03)	(44,586,349.40)	(124,483,074.43)
11	**Central Gulf Service Area Other Rate Base Items**	(5,420,956.13)	(3,136,046.79)	(8,557,002.92)
12	**TGS Division Plant Assets Depreciation**	(58,273.38)	(264,572.90)	(322,846.28)
13	**ONEGAS Plant Assets Depreciation**	(2,766,139.92)	(1,541,999.99)	(4,308,139.91)
14	**Central Gulf Service Area NOL**	36,180,704.51	21,068,802.65	57,249,507.16
16	**ADFIT - Accumulated Deferred Federal Income Taxes**	(51,961,390)	(28,460,166)	(80,421,556)

Accumulated Deferred Income Tax - Central Gulf Service Area Plant Related Items

Row	As of Sept 30, 2019 Town	Gross Book Basis	Book Reserve	Net Book Basis	Gross Tax Basis	Tax Reserve	Net Tax Basis	Difference in Net Plant Basis	Estimated ADIT Asset/(Liability) at 21%
25	Austin Area	551,978,335	(149,421,920)	402,556,415	294,396,037	(174,642,704)	119,753,332		
26	Buda	622,658	(17,663)	604,995	596,261	(92,238)	504,023		
27	Kyle	6,901,441	(435,880)	6,465,561	4,314,059	(1,592,398)	2,721,661		
28	Nixon	699,670	192,734	892,404	507,360	(224,509)	282,852		
29	Other South Tx Towns	30,951,382	(3,945,350)	27,006,032	13,377,941	(7,319,390)	6,058,552		
30	Total Central Texas	591,153,485	(153,628,078)	437,525,407	313,191,659	(183,871,239)	129,320,420		
32	Galveston	34,522,582	(11,348,593)	23,173,989	18,845,888	(12,044,309)	6,801,579		
33	South Jefferson	66,324,468	(15,626,628)	50,697,840	31,319,306	(20,538,695)	10,780,611		
34		100,847,050	(26,975,221)	73,871,828	50,165,194	(32,583,005)	17,582,190		
36	Central Gulf Service Area Direct Plant	692,000,535	(180,603,300)	511,397,235	363,356,853	(216,454,243)	146,902,610	364,494,625	(76,543,871)
37				-			-		
38	Central Tx 101 Retirement Adjustments	(2,038,101)		(2,038,101.00)					
39	Central Tx 108 Retirement Adjustments		2,038,101	2,038,101.00					
40	Central Tx 108 Retirement Work in Progress Adj.		5,547,187	5,547,187.00					
41	Central Tx 101 Adjustment - OPC High Pressure Line	8,024,125		8,024,125.00					
42	Central Tx 108 Adjustment - OPC High Pressure Line		(2,973,659)	(2,973,659.00)					
43	Central Tx 101 Adjustments - Other	6,790		6,789.57					
44	Central Tx 106 Adjustments	10,297,228		10,297,227.97					
45	Central Tx 108/111 Adjustments - Other		1,212,582	1,212,582.03					
46	Subtotal Central Tx Adjustments	16,290,042	5,824,211	22,114,253	5,459,043	1,451,290	6,910,334	15,203,919	(3,192,823)
48	Gulf Coast 101 Retirement Adjustments	(1,046,273)		(1,046,273.00)					
49	Gulf Coast 108 Retirement Adjustments		1,046,273	1,046,273.00					
50	Gulf Coast 108 RWIP Adjustments		611,396	611,396.00					
51	Gulf Coast 101 Adjustments - Other	(521)		(520.74)					
52	Gulf Coast 106 Adjustments	380,477		380,476.94					
53	Gulf Coast 108/111 Adjustments - Other		193,838	193,838.39					
54	Subtotal Gulf Coast Adjustments	(666,317)	1,851,507	1,185,191	189,005	234,135	423,140	762,051	(160,031)
56	Subtotal Adjustments	15,623,725	7,675,718	23,299,443	5,648,048	1,685,425	7,333,473	15,965,970	(3,352,854)
58	**Adjusted Central Gulf Service Area**	**707,624,260**	**(172,927,581)**	**534,696,678**	**369,004,901**	**(214,768,818)**	**154,236,083**	**380,460,595**	**(79,896,725)**
60	**TGS Division (Allocated to Central Gulf Service Area)**	**3,654,287**	**(1,378,530)**	**2,275,758**	**3,930,880**	**(1,932,615)**	**1,998,265**	**277,492**	**(58,273)**
62	**ONEGas (Allocated to Central Gulf Service Area)**	**26,582,838**	**(7,876,676)**	**18,706,162**	**17,646,337**	**(12,112,269)**	**5,534,068**	**13,172,095**	**(2,766,140)**

Accumulated Deferred Income Tax Analysis For Central Gulf Service Area Other Rate Base Items

Row		Balance Sheet Impact per Book	Balance Sheet Impact per Tax	Difference	Estimated ADIT Asset/(Liability)
70	Pension/OPEB Expense Regulatory Deferrals	1,944,459	-	1,944,459	(408,336)
72	Prepaid Pension (funding in excess of FAS87 expense)	23,340,795	-	23,340,795	(4,901,567)
74	Section 8.209 Deferral	528,823	-	528,823	(111,053)
76	Total Other Rate Base Items				(5,420,956)

Exhibit JMS-2
Page 1 of 1

SUMMARY ADIT ALLOCATIONS TO CENTRAL TEXAS SERVICE AREA
For General Rate Case - Test Year Ended 9/30/2019

Estimated Accumulated Deferred Income Taxes for:	ADIT at 21%	Unamortized Excess ADIT - Bal at 9/30/2019	Total CTSA ADIT and Excess ADIT at 9/30/2019
Central TexasService Area Plant Assets Depreciation	(52,951,209)	(28,694,365)	(81,645,574)
Central Texas Service Area Direct Plant Repairs	(14,964,661)	(8,319,002)	(23,283,663)
Subtotal CTSA Direct Plant Assets Depreciation	(67,915,870)	(37,013,367)	(104,929,237)
Central Texas Service Area Other Rate Base Items	(4,680,500)	(2,676,419)	(7,356,919)
TGS Division Plant Assets Depreciation	(49,842)	(225,312)	(275,154)
ONEGAS Plant Assets Depreciation	(2,365,913)	(1,308,791)	(3,674,704)
Central Texas Service Area NOL	34,914,608	19,296,333	54,210,941
ADFIT - Accumulated Deferred Federal Income Taxes	(40,097,517)	(21,927,556)	(62,025,073)

Accumulated Deferred Income Tax - Central Texas Service Area Plant Related Items

As of Sept 30, 2019 Town	Gross Book Basis	Book Reserve	Net Book Basis	Gross Tax Basis	Tax Reserve	Net Tax Basis	Difference in Net Plant Basis	Estimated ADIT Asset/(Liability) at 21%
Austin Area	551,978,335	(149,421,920)	402,556,415	294,396,037	(174,642,704)	119,753,332		
Buda	622,658	(17,663)	604,995	596,261	(92,238)	504,023		
Kyle	6,901,441	(435,880)	6,465,561	4,314,059	(1,592,398)	2,721,661		
Nixon	699,670	192,734	892,404	507,360	(224,509)	282,852		
Other South Tx Towns	30,951,382	(3,945,350)	27,006,032	13,377,941	(7,319,390)	6,058,552		
Total Central Texas	591,153,485	(153,628,078)	437,525,407	313,191,659	(183,871,239)	129,320,420	308,204,987	(64,723,047)
Central Tx 101 Retirement Adjustments	(2,038,101)		(2,038,101.00)					
Central Tx 108 Retirement Adjustments		2,038,101	2,038,101.00					
Central Tx 108 Retirement Work in Progress Adj.		5,547,187	5,547,187.00					
Central Tx 101 Adjustment - OPC High Pressure Line	8,024,125		8,024,125.00					
Central Tx 108 Adjustment - OPC High Pressure Line		(2,973,659)	(2,973,659.00)					
Central Tx 101 Adjustments - Other	6,790		6,789.57					
Central Tx 106 Adjustments	10,297,228		10,297,227.97					
Central Tx 108/111 Adjustments - Other		1,212,582	1,212,582.03					
Subtotal Central Tx Adjustments	16,290,042	5,824,211	22,114,253	5,459,043	1,451,290	6,910,334	15,203,919	(3,192,823)
Adjusted Central Texas Service Area	**607,443,527**	**(147,803,867)**	**459,639,660**	**318,650,702**	**(182,419,948)**	**136,230,754**	**323,408,906**	**(67,915,870)**
TGS Division (Allocated to Central Texas Service Area)	**3,125,557**	**(1,179,073)**	**1,946,483**	**3,362,129**	**(1,652,989)**	**1,709,141**	**237,343**	**(49,842)**
ONEGas (Allocated to Central Texas Service Area)	**22,736,625**	**(6,737,017)**	**15,999,609**	**15,093,127**	**(10,359,771)**	**4,733,355**	**11,266,253**	**(2,365,913)**

Accumulated Deferred Income Tax Analysis For Central Texas Service Area Other Rate Base Items

	Balance Sheet Impact per Book	Balance Sheet Impact per Tax	Difference	Estimated ADIT Asset/(Liability)
Pension/OPEB Expense Regulatory Deferrals	1,856,196	-	1,856,196	(389,801)
Prepaid Pension (funding in excess of FAS87 expense)	19,963,666	-	19,963,666	(4,192,370)
Section 8.209 Deferral	468,231	-	468,231	(98,329)
Total Other Rate Base Items				(4,680,500)

Exhibit JMS-3
Page 1 of 1

SUMMARY ADIT ALLOCATIONS TO GULF COAST SERVICE AREA
For General Rate Case - Test Year Ended 9/30/2019

Estimated Accumulated Deferred Income Taxes for:	ADIT at 21%	Unamortized Excess ADIT - Bal at 9/30/2019	Total GCSA ADIT and Excess ADIT at 9/30/2019
Gulf Coast Service Area Plant Assets Depreciation	(8,382,580)	(5,269,984)	(13,652,564)
Gulf Coast Service Area Direct Plant Repairs	(3,598,275)	(2,302,998)	(5,901,273)
Subtotal GCSA Direct Plant Assets Depreciation	(11,980,855)	(7,572,983)	(19,553,837)
Gulf Coast Service Area Other Rate Base Items	(740,456)	(459,628)	(1,200,084)
TGS Division Plant Assets Depreciation	(8,431)	(39,261)	(47,692)
ONEGAS Plant Assets Depreciation	(400,227)	(233,209)	(633,436)
Gulf Coast Service Area NOL	1,266,097	1,772,469	3,038,566
ADFIT - Accumulated Deferred Federal Income Taxes	(11,863,873)	(6,532,611)	(18,396,483)

Accumulated Deferred Income Tax - Gulf Coast Service Area Plant Related Items

As of Sept 30, 2019 Town	Gross Book Basis	Book Reserve	Net Book Basis	Gross Tax Basis	Tax Reserve	Net Tax Basis	Difference in Net Plant Basis	Estimated ADIT Asset/(Liability) at 21%
Galveston	34,522,582	(11,348,593)	23,173,989	18,845,888	(12,044,309)	6,801,579		
South Jefferson	66,324,468	(15,626,628)	50,697,840	31,319,306	(20,538,695)	10,780,611		
	100,847,050	(26,975,221)	73,871,828	50,165,194	(32,583,005)	17,582,190	56,289,639	(11,820,824)
Gulf Coast Service Area Direct Plant	100,847,050	(26,975,221)	73,871,828	50,165,194	(32,583,005)	17,582,190	56,289,639	(11,820,824)
			-			-		
Gulf Coast 101 Retirement Adjustments	(1,046,273)		(1,046,273.00)					
Gulf Coast 108 Retirement Adjustments		1,046,273	1,046,273.00					
Gulf Coast 108 RWIP Adjustments		611,396	611,396.00					
Gulf Coast 101 Adjustments - Other	(521)		(520.74)					
Gulf Coast 106 Adjustments	380,477		380,476.94					
Gulf Coast 108/111 Adjustments - Other		193,838	193,838.39					
Subtotal Gulf Coast Adjustments	(666,316.80)	1,851,507.39	1,185,190.59	189,004.80	234,134.76	423,140	762,051	(160,031)
Subtotal Adjustments	(666,317)	1,851,507	1,185,191	189,005	234,135	423,140	762,051	(160,031)
Adjusted Gulf Coast Service Area	**100,180,733**	**(25,123,714)**	**75,057,019**	**50,354,199**	**(32,348,870)**	**18,005,329**	**57,051,690**	**(11,980,855)**
TGS Division (Allocated to Gulf Coast Service Area)	**528,731**	**(199,456)**	**329,274**	**568,750**	**(279,626)**	**289,125**	**40,150**	**(8,431)**
ONEGas (Allocated to Gulf Coast Service Area)	**3,846,213**	**(1,139,659)**	**2,706,554**	**2,553,210**	**(1,752,498)**	**800,712**	**1,905,842**	**(400,227)**

Accumulated Deferred Income Tax Analysis For Gulf Coast Service Area Other Rate Base Items

	Balance Sheet Impact per Book	Balance Sheet Impact per Tax	Difference	Estimated ADIT Asset/(Liability)
Pension/OPEB Expense Regulatory Deferrals	88,263	-	88,263	(18,535)
Prepaid Pension (funding in excess of FAS87 expense)	3,377,129	-	3,377,129	(709,197)
Section 8.209 Deferral	60,592	-	60,592	(12,724)
Total Other Rate Base Items				(740,456)

Exhibit JMS-4
Page 1 of 1

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 a Principal in Dively &Associates, PLLC, a public accounting firm specializing in regulatory and forensic accounting. 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.

Janet Simpson
____
Janet Simpson

SUBSCRIBED AND SWORN TO BEFORE ME by the said Janet Simpson on this 2 day of December, 2019.

____
Notary Public in and for the State of Texas

MARYNELL MYERS
Notary Public, State of Texas
Notary ID # 12603951-6
My Commission Expires
August 4, 2021

NOTARY PUBLIC STATE OF TEXAS

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

DR. RONALD E. WHITE

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

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 an M.S. degree and Ph.D. degree 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 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. Before 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. A more detailed description of my professional qualifications is contained in Attachment REW–1.

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 2019 depreciation rate study for: a) plant located in a proposed Central–Gulf Service Area (CGSA), which consolidates the Central Texas Service Area (CTSA) and the Gulf Coast Service Area (GCSA); and b) for common facilities shared among all TGS Service Areas (the TGS Division).[1] Accompanying my testimony are the following attachments:

a) Attachment REW–1 is a description of my professional qualifications.

b) Attachment REW–2 is the 2019 study for the Central–Gulf Service Area and the TGS Division.

The purpose of my testimony is to sponsor and describe the studies 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

[1] Plant serving the City of Beaumont is located in the GCSA.

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.[2]

[2] I do not discuss nor have I considered whether other regulatory or public policy goals should influence or be reflected in establishing depreciation rates. Such considerations remain the prerogative of the regulatory agency responsible for prescribing appropriate depreciation rates.

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 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. 2019 TGS DEPRECIATION STUDIES

Q. PLEASE DESCRIBE THE SOURCE OF DEPRECIATION RATES CURRENTLY USED BY TGS FOR THE PROPOSED CGSA.

A. Current depreciation rates for CTSA and the TGS Division were developed in a 2015 study conducted by Foster Associates based on December 31, 2014 plant and depreciation reserves. Rates developed for CTSA were approved by the Railroad Commission of Texas pursuant to a Settlement Agreement in GUD No. 10526 (Final Order dated November 15, 2016). Current depreciation rates for GCSA were developed in a 2015 update of a 2013 study and approved by the Commission pursuant to a Settlement Agreement in GUD No. 10488 (Final Order dated May 3, 2016).

Q. DID TGS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2019 DEPRECIATION STUDY?

A. Yes. The database used in the 2019 study was assembled by appending 2018 plant and reserve activity to the statewide data base used in conducting a 2018 update for the North Texas Service Area (NTSA). 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, 2018 were derived by Foster Associates in a forward–flow calculation in which accounting activity was appended to the database used in the 2018 study. The accuracy and completeness of the assembled data base was validated for 2018 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. Derived age distributions at December 31, 2018 were also reconciled to the continuing property records of TGS. Annual plant activity prior to 2018 was reconciled in the 2018 and prior depreciation rate studies.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR TGS PLANT AND EQUIPMENT?

A. Yes. As discussed in Attachment REW–2, 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 six service areas and the TGS Division that supports all service areas.[3] Projection lives and projection curves were estimated in the TGS study from the combined database of the existing six 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 CGSA 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 needed for TGS. Total plant included in the 2019 study at December 31, 2018 for TGS (including the TGS Division) was $1,360,877,342. The amount of investment in each of the existing six service areas ranges between $14.6 million for Borger/Skellytown and $557.4 million for the existing Central Texas Service Area. CTSA represents 41.0 percent of TGS total plant investments and GCSA represents $98.8 million or 7.3 percent of TGS total plant investments.

Plant investments located in the six 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

[3] Existing service areas include: Borger/Skellytown; North Texas; Rio Grande Valley; West Texas; Central Texas and Gulf Coast.

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 2019 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 six 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. Increasing net salvage rates (*i.e*. the ratio of net salvage to retirements) observed over the last ten years is partially attributable to cost of removal stated in current dollars divided by retirements stated in dollars at the year of installation. The cost per foot to retire a gas main today, for example, is no different for a main that was installed yesterday or a main that was installed many years ago. The percentage rate applied to the cost of an old asset to accrue the same cost per unit to retire a new asset, however, depends upon the relative difference in the cost per unit incurred to install the assets. The percentage rate required to accrue for $100 per foot of removal expense on a main costing $50 per foot to install is twice the rate required to accrue the same amount of removal expense on a main costing $100 per foot to install.

The extent to which past inflation is captured in the ratio of cost of removal to retirements is a function of both the rate of change in the cost of labor required to abandon or remove plant from service and the rate of change in the installed unit cost of plant retired from service. While realized net salvage is independent of the age of retirements, revenue requirements created for cost of removal must be recovered in dollars sufficient to pay the cost of removal or abandonment when the associated plant is retired from service.

A second contributing factor to increasing net salvage rates is costs imposed by local requirements such as mandatory police traffic control or curb–to–curb refurbishment when a much smaller section of roadway is disturbed in a plant replacement project.

ONE Gas in general and TGS in particular became increasingly mindful of the apparent upward trend in net savage rates. Based on an internal investigation, standard material and labor costs were recently assigned to retirement units for both installation and retirement/removal activities. The new standards were adopted in March 2018.

It is the opinion of Foster Associates that it is premature to adjust currently approved net salvage rates for mains and services based on the recently developed retirement unit standards. The magnitude and trend of future net salvage rates will not be observable until the new standards have been applied for a number of years. The recently adopted retirement unit standards may permit a per–unit formulation of future net salvage rates that should be explored in future depreciation studies. With consideration given to the above factors, Foster Associates is recommending to retain future net salvage rates currently approved for transmission mains (Account 367.00), distribution mains (Account 376.00) and distribution services (Account 380.00)

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes. Statement C of Attachment REW–2 provides a comparison of recorded, computed and redistributed reserves at December 31, 2018. The recorded reserve for the CGSA was $167,281,380 or 25.5 percent of the depreciable plant investment. The corresponding computed reserve is $149,644,601 or 22.8 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $17,636,779 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Recorded reserves for the TGS Division at December 31, 2018 were set equal to computed reserves of $3,391,838 or 67.7 percent of the amortizable plant investment. The equivalency between recorded and computed reserves (a condition required for amortization accounting) was achieved by transferring recorded reserves, in proportion to customer count, from Account 390.10 (Structures and Improvements) from each jurisdiction in which investments were recorded in Account 390.10. The amount of reserve transferred to the TGS Division from CTSA was $361,194 and $61,509 was transferred from GCSA.

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

[4] See, for example, GUD Nos. 10488 and 10526.

the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability. Recorded reserves should also be realigned to eliminate reserve imbalances created by the implementation of amortization accounting.

Recorded reserves were rebalanced 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 general support asset categories for which amortization accounting has been approved, TGS is currently using a depreciation system composed of the straight–line method, vintage group procedure and, remaining–life technique for all rate categories in the CTSA, GCSA and 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.

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 2019 STUDY CHANGED FROM THE SYSTEM CURRENTLY APPROVED FOR TGS?

A. No. The system used for all service areas was retained in the 2019 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 2019 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 CGSA.

	Accrual Rate			2019 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	1.88%	1.77%	-0.11%	$ 135,901	$ 127,302	$ (8,599)
Distribution	2.31%	2.51%	0.20%	13,899,684	15,047,190	1,147,506
General Plant	6.20%	6.53%	0.33%	3,005,043	3,164,654	159,611
Total	2.60%	2.79%	0.19%	$ 17,040,628	$ 18,339,146	$ 1,298,518

Table 1. Central-Gulf Service Area

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.79 percent. Depreciation expense is currently accrued at rates that composite to 2.60 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.19 percentage points.

A continued application of current rates would provide annualized depreciation expense of $17,040,628 compared with an annualized expense of $18,339,146 using the rates developed in this study. The proposed 2019 expense increase is $1,298,518.

Table 2 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 CTSA.

	Accrual Rate			2019 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	1.88%	1.77%	-0.11%	$ 135,901	$ 127,302	$ (8,599)
Distribution	2.24%	2.48%	0.24%	11,469,125	12,673,628	1,204,503
General Plant	6.21%	6.67%	0.46%	2,425,550	2,603,243	177,693
Total	2.52%	2.76%	0.24%	$ 14,030,576	$ 15,404,173	$ 1,373,597

Table 2. Central Texas Service Area

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.76 percent. Depreciation expense is currently accrued at rates that composite to 2.52 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.24 percentage points.

A continued application of current rates would provide annualized depreciation expense of $14,030,576 compared with an annualized expense of $15,404,173 using the rates developed in this study. The proposed 2019 expense increase is $1,373,597.

Table 3 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 GCSA.

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.97 percent. Depreciation expense is currently accrued at rates that composite to 3.05 percent. The recommended change in the

Function	Accrual Rate Current	Accrual Rate Proposed	Accrual Rate Difference	2019 Annualized Accrual Current	2019 Annualized Accrual Proposed	2019 Annualized Accrual Difference
A	B	C	D=C-B	E	F	G=F-E
Distribution	2.72%	2.66%	-0.06%	$ 2,430,559	$ 2,373,561	$ (56,998)
General Plant	6.15%	5.96%	-0.19%	579,493	561,411	(18,082)
Total	3.05%	2.97%	-0.08%	$ 3,010,052	$ 2,934,972	$ (75,080)

Table 3. Gulf Coast Service Area

composite depreciation rate is, therefore, a decrease of 0.08 percentage points.

A continued application of current rates would provide annualized depreciation expense of $3,010,052 compared with an annualized expense of $2,934,972 using the rates developed in this study. The proposed 2019 expense decrease is $75,080.

Table 4 below provides a summary of the changes in annual rates and accruals resulting from the parameters and depreciation rates recommended for the TGS Division.

Function	Accrual Rate Current	Accrual Rate Proposed	Accrual Rate Difference	2019 Annualized Accrual Current	2019 Annualized Accrual Proposed	2019 Annualized Accrual Difference
A	B	C	D=C-B	E	F	G=F-E
General Plant	9.90%	9.90%		$ 496,158	$ 496,025	($133)
Total	9.90%	9.90%		$ 496,158	$ 496,025	($133)

Table 4. TGS Division

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 9.90 percent. Depreciation expense is currently accrued at rates that composite to 9.90 percent. No change is recommended in the composite depreciation rate.

A continued application of current rates would provide annualized depreciation expense of $496,158 compared with an annualized expense of $496,025 using the rates developed in this study. The resulting 2019 expense reduction is $133, attributable to rounding of trailing digits.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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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. 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.

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. 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 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.

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State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.

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Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

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Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, et. al. File No. 394126; testimony concerning depreciation and engineering economics.

Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

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.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

Speaker

Depreciation Training Seminar, Kansas Gas Service, October 2018.

Depreciation Workshop, Oklahoma Corporation Commission, Public Utility Division, March 2015.

Depreciation Workshop, ONE Gas, Inc. January 2015.

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Depreciation and Obsolescence (Isness and Oughtness), Ninety–Fifth Annual Arizona Tax Conference, August 2012.

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Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

Octoberr 2019

Attachment REW–2

2019 Depreciation Rate Study

Texas Gas Service

A Division of ONE Gas

– Central–Gulf
– TGS Division

foster associates

CONTENTS

Analysis

Section V

Distribution

EXECUTIVE SUMMARY

INTRODUCTION

This report presents findings and recommendations developed in a 2019 depreciation study conducted by Foster Associates Consultants, LLC (Foster Associates) for gas plant owned and operated by Texas Gas Service (TGS), a division of ONE Gas, Inc., and located in the Central–Gulf Service Area (CGSA). The study also includes TGS Division, 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 life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned businesses including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

At the request of TGS, the CGSA was created in the 2019 study by consolidating the Central Texas Service Area (CTSA) and the Gulf Coast Service Area (GCSA). Service areas consolidated into the CGSA are shown in Figure 1 below.

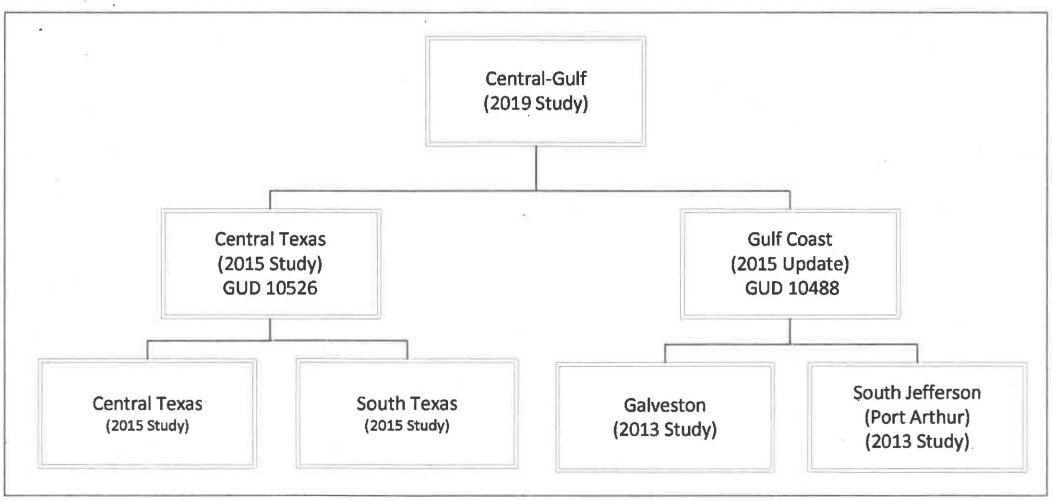


Figure 1. Central-Gulf Consolidated Service Areas

Recommended parameters (*i.e.*, projection curves, projection lives and future net salvage rates) estimated for the CGSA were derived from a 2019 combined analysis of all TGS Service Areas. Proposed depreciation rates for the CGSA were derived from a weighted average of accrual rates developed separately for CTSA and GCSA. Rates for each of the two Service Areas were derived from age distributions of surviving plant, recorded depreciation reserves and average net salvage rates specific to each Service Area.

Current depreciation rates for CTSA and the TGS Division were developed in a 2015 study conducted by Foster Associates based on December 31, 2014 plant and depreciation reserves. Rates developed for CTSA were approved by the Railroad Commission of Texas pursuant to a Settlement Agreement in GUD 10526 (Order dated November 15, 2016). Current depreciation rates for GCSA were developed in a 2015 update of a 2013 study and approved by the Commission pursuant to a Settlement Agreement in GUD 10488 (Order dated May 3, 2016).

The principal findings and recommendations of the 2019 CGSA study are summarized in Section IV (Statements) of this report. A corresponding set of statements is provided for both CGSA and the TGS Division. Depreciation rates for CGSA are also developed separately for CTSA and GCSA.

Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides of summary of the investment and net salvage components of rebalanced reserves. Statement E provides a summary of the components used to obtain weighted–average net salvage rates. Statement F provides a comparative summary of current and proposed parameters including projection life, projection curve and future net salvage rates. Statement F also contains current and proposed statistics including average service lives, average remaining lives, and average net salvage rates.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to Company official records;
- Discussions with TGS 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 CTSA, GCSA and the TGS Division. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.,* credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period. Any realized net salvage for amortizable accounts is netted against current–year vintage additions.

Depreciation theory provides that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the approved amortization categories.

PROPOSED DEPRECIATION RATES

Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation rates recommended for CGSA.

	Accrual Rate			2019 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	1.88%	1.77%	-0.11%	$ 135,901	$ 127,302	$ (8,599)
Distribution	2.31%	2.51%	0.20%	13,899,684	15,047,190	1,147,506
General Plant	6.20%	6.53%	0.33%	3,005,043	3,164,654	159,611
Total	2.60%	2.79%	0.19%	$ 17,040,628	$ 18,339,146	$ 1,298,518

Table 1. Central-Gulf Consolidated Service Area

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.79 percent. Depreciation expense is currently accrued at rates that composite to 2.60 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.19 percentage points.

A continued application of current rates would provide annualized depreciation expense of $17,040,628 compared with an annualized expense of $18,339,145 using the rates developed in this study. The proposed 2019 expense increase is $1,298,518. The computed change in annualized accruals includes a reduction of $1,050,028 attributable to an amortization of a $17,636,779 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2019 study. Of the 44 plant accounts included in the 2019 study, Foster Associates is recommending rate reductions for 13 accounts, rate increases for 14 accounts and no rate changes for 17 accounts.

Table 2 below provides a summary of annual rates and accruals for the TGS Division in which all plant accounts are amortizable.

	Accrual Rate			2015 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
General Plant	9.90%	9.90%		$ 496,158	$ 496,025	$ (133)
Total	9.90%	9.90%		$ 496,158	$ 496,025	$ (133)

Table 2. TGS Division

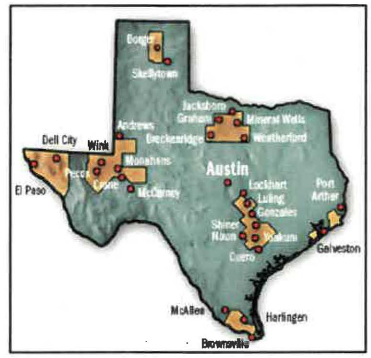
Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 9.90 percent. Depreciation expense is currently accrued at rates that composite to 9.90 percent. No change is recommended in the composite depreciation rate.

A continued application of current rates would provide annualized depreciation expense of $496,158 compared with an annualized expense of $496,025 using the rates developed in this study. The resulting 2019 expense reduction is $133, attributable to rounding of trailing digits.

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, 2018, Texas Gas Service owned and operated approximately 10,225 miles of distribution mains and 310 miles of transmission mains. The distribution system consists of 5,248 miles of cathodically protected pipe, 562 miles of unprotected steel pipe, 31miles of cast/wrought iron and 4,384 miles of plastic mains. All transmission mains are cathodically protected.

At the end of 2018, Texas Gas Service maintained 671,336 service lines consisting of 48,936 unprotected lines, 232,898 cathodically protected lines, 216 copper lines and 338,877 plastic lines.

The Company owns and operates 124 city gate stations serving wholesale and retail customers. A total of 14 service centers are located in Central Texas, North Texas, West Texas, the Rio Grande Valley and the Gulf Coast.

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 663,000 customers including residential, commercial, industrial, and transportation. Texas Gas Service serves more than 100 communities. The Company's largest Service Areas are Austin, El Paso, and the Rio Grande Valley. In addition, Texas Gas Service provides service to customers in Galveston, Port Arthur, Mineral Wells, several towns south of Austin, including Lockhart and several communities in the Permian Basin and the Texas panhandle.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of depreciation accruals and recorded depreciation reserves for each rate category. This study provides the foundation and documentation for recommended changes in depreciation rates used by TGS for CGSA 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 2019 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 2019 study was assembled by appending 2018 plant and reserve activity to the statewide data base used in conducting a 2018 update for the North Texas Service Area (NTSA). 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, 2018 were derived by Foster Associates in a forward–flow calculation in which accounting activity was appended to the database used in the 2018 study. The accuracy and completeness of the assembled data base was validated for 2018 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. Derived age distributions at December 31, 2018 were also reconciled to the continuing property records of TGS. Annual plant activity prior to 2018 was reconciled in the 2018 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 2019 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 2019 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. 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.

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 six (6) 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 six service areas. Average service lives and remaining service lives were distinguished among service areas in the development of vintage–group depreciation rates.

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[1] Service areas include: Borger/Skellytown; North Texas; Rio Grande Valley; West Texas; Central Texas and Gulf Coast.

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 six service areas. Future net salvage rates were estimated in the TGS study from the combined database of the six 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 2019 study to: a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements *(i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as the weighting of future net salvage estimates changes from the installation of subsequent plant additions. The computation of estimated average net salvage rates is shown in Statement E.

Future net salvage rates currently approved for transmission mains (Account

367.00), distribution mains (Account 376.00) and distribution services (Account 380.00) are significantly lower than historical indications would suggest. Increasing net salvage rates (*i.e.* the ratio of net salvage to retirements) observed over the last ten years is partially attributable to cost of removal stated in current dollars divided by retirements stated in dollars at the year of installation. The cost per foot to retire a gas main today, for example, is no different for a main that was installed yesterday or a main that was installed many years ago. The percentage rate applied to the cost of an old asset to accrue the same cost per unit to retire a new asset, however, depends upon the relative difference in the cost per unit incurred to install the assets. The percentage rate required to accrue for $100 per foot of removal expense on a main costing $50 per foot to install is twice the rate required to accrue the same amount of removal expense on a main costing $100 per foot to install.

The extent to which past inflation is captured in the ratio of cost of removal to retirements is a function of both the rate of change in the cost of labor required to abandon or remove plant from service and the rate of change in the installed unit cost of plant retired from service. While realized net salvage is independent of the age of retirements, revenue requirements created for cost of removal must be recovered in dollars sufficient to pay the cost of removal or abandonment when the associated plant is retired from service.

A second contributing factor to increasing net salvage rates is costs imposed by local requirements such as mandatory police traffic control or curb–to–curb refurbishment when a much smaller section of roadway is disturbed in a plant replacement project.

ONE Gas in general and TGS in particular became increasingly concerned over the apparent upward trend in net savage rates. Based on an internal investigation, standard material and labor costs were assigned to retirement units for both installation and retirement/removal activities. The new standards were adopted in March 2018.

It is the opinion of Foster Associates that it is premature to adjust currently approved net salvage rates for mains and services based on the recently developed retirement unit standards. The magnitude and trend of future net salvage rates will not be observable until the new standards have been applied for a number of years. It is also the opinion of Foster Associates that the recently adopted retirement unit standards may permit a per–unit formulation of future net salvage rates that should be explored in future depreciation studies.

Based on the above considerations, it is recommended that currently approved net salvage rates of: –10 percent for transmission mains; –20 percent for distribution mains and –30 percent for services be retained in the current depreciation study. These rates were initially approved for El Paso in GUD No. 9988 (Order dated

December 14, 2010) and subsequently adopted in West Texas GUD No. 10506 (Order dated September 27, 2016, GCSA GUD 10488 and CTSA GUD 10526.

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. If statistical life studies have not been conducted or retirement dispersion has been overlooked in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated or theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of service lives, retirement dispersion and net salvage rates.

A redistribution of recorded reserves is considered appropriate for TGS at this time. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability. Recorded reserves should also be realigned to eliminate reserve imbalances created by the implementation of amortization accounting.

Recorded reserves were rebalanced 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 measured theoretical reserves and distributing any reserve imbalances to depreciable categories.

Statement C provides a comparison of recorded, computed and redistributed reserves at December 31, 2018. The recorded reserve for the CGSA was \$167,281,380 or 25.5 percent of the depreciable plant investment. The corresponding computed reserve is \$149,644,601 or 22.8 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of \$17,636,779 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Recorded reserves for the TGS Division at December 31, 2018 sere set equal to computed reserves of \$3,391,828 or 67.7 percent of the amortizable plant investment. The equivalency between recorded and computed reserves (a condition required for amortization accounting) 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 Account390.10, The amount of reserve transferred to the TGS Division from CTSA was \$361,194 and \$61,509 was transferred from GCSA. Reserve amounts totaling \$910,056 transferred from each service area are shown in Figure 2 below.

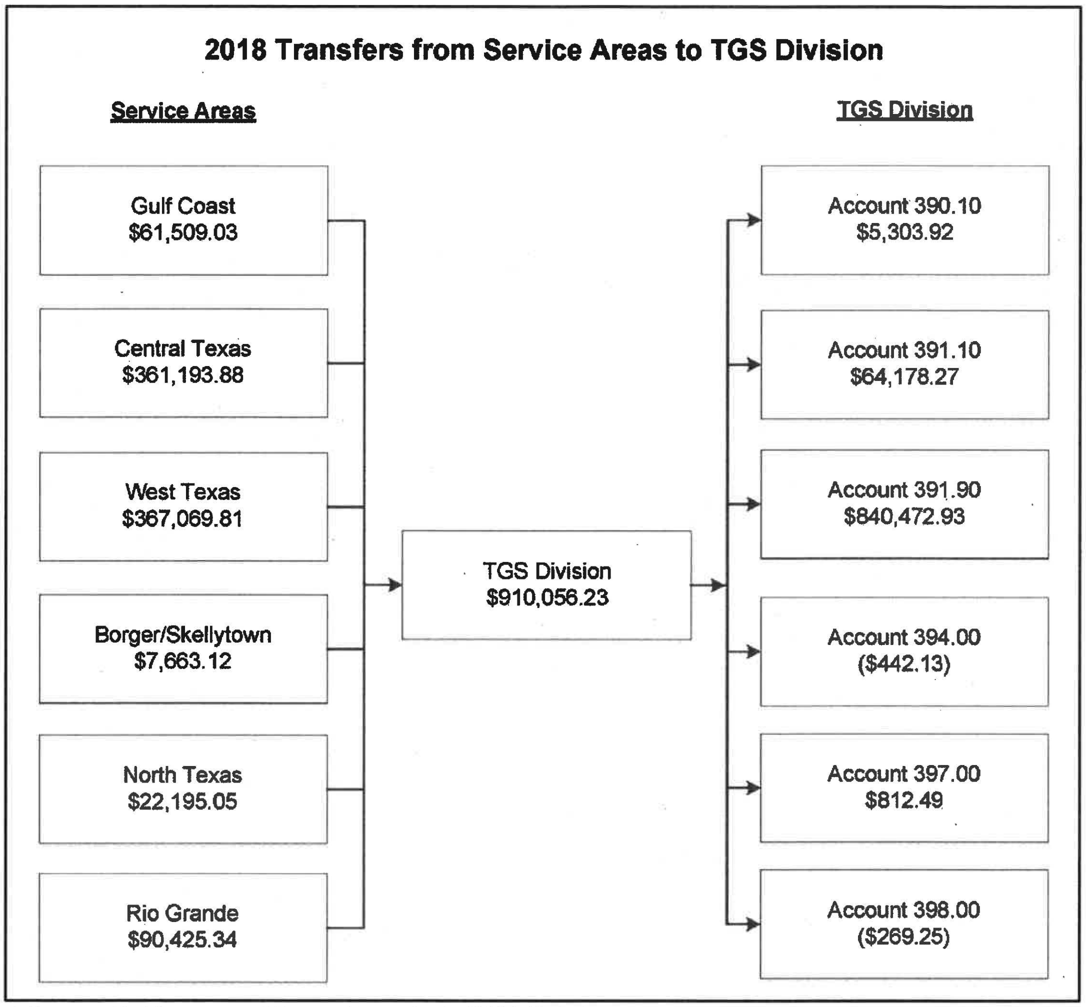

Figure 2. Reserve Transfers to TGS Division

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. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole–life and remaining–life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2019 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 six (6) 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 six 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 general plant categories relieves TGS of the burden of maintaining detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the assets.

The treatment of amortization accounts in the current study was designed to produce annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after retirements have been recorded. Applying a rate equal to the reciprocal of the amortization period to plant balances prior to posting retirements would overstate the annualized amortization expense. Accrual rates contained in Statement A have been applied to plant balances containing vintages that will be retired upon approval and implementation of amortization accounting. Accrual rates contained in Statement A should be applied to current plant balances. Accrual rates equal to the reciprocal of the amortization period should be applied to these categories after plant balances have been reduced by all vintages that have achieved an age equal to the amortization period.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded, computed and redistributed depreciation reserves, and current and proposed service life and net salvage parameters recommended for TGS plant and equipment categories. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2019 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, 2018.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain weighted average net salvage rates.
- Statement F provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of plant investments (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by TGS for the mix of investments recorded at December 31, 2018. 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.

Central–Gulf Service Area

Statements A through F

TEXAS GAS SERVICE - Central-Gulf Service Area Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2018) Investment	Salvage	Total	Proposed (at 12/31/2018) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
CENTRAL-GULF SERVICE AREA						
TRANSMISSION PLANT						
367.00 Mains	1.38%	0.14%	1.52%	1.58%	0.17%	1.75%
369.00 Meas. and Reg. Station Equipment	3.44%		3.44%	1.66%	0.17%	1.83%
Total Transmission Plant	1.77%	0.11%	1.88%	1.60%	0.17%	1.77%
DISTRIBUTION PLANT						
375.10 Structures and Improvements	2.39%	0.14%	2.53%	1.67%	0.03%	1.71%
375.20 Other System Structures	2.47%	0.12%	2.59%	2.27%	0.11%	2.38%
376.00 Mains	1.40%	0.36%	1.76%	1.47%	0.41%	1.88%
376.90 Mains - Cathodic Protection	6.22%		6.24%	← 15 Year Amortization →		6.24%
378.00 Meas. and Reg. Station Equip. - General	1.69%	0.35%	2.04%	1.75%	0.37%	2.12%
379.00 Meas. and Reg. Station Equip. - City Gate	1.54%	0.19%	1.73%	1.50%	0.20%	1.69%
380.00 Services	1.55%	0.68%	2.23%	1.72%	0.83%	2.55%
381.00 Meters	3.41%	0.36%	3.78%	3.55%	0.48%	4.04%
383.00 House Regulators	2.01%	0.09%	2.10%	2.36%	0.19%	2.55%
385.00 Industrial Meas. and Reg. Station Equip.	1.58%	0.48%	2.06%	1.70%	0.44%	2.15%
386.00 Other Property on Customers' Premises	-0.76%	-0.05%	-0.81%	-0.12%	-0.04%	-0.16%
Total Distribution Plant	1.88%	0.43%	2.31%	1.99%	0.51%	2.51%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.40%	0.10%	2.51%	2.35%	0.11%	2.46%
392.00 Transportation Equipment	7.91%	-0.67%	7.25%	9.07%	-0.59%	8.49%
396.00 Power Operated Equipment	5.36%	-0.58%	4.78%	6.05%	-0.59%	5.46%
Total Depreciable	6.32%	-0.47%	5.86%	7.14%	-0.41%	6.73%
Amortizable						
391.10 Office Furniture and Fixtures			6.52%	← 15 Year Amortization →		6.52%
391.90 Computers and Electronic Equipment			4.90%	← 7 Year Amortization →		4.90%
393.00 Stores Equipment			6.67%	← 15 Year Amortization →		6.67%
394.00 Tools, Shop and Garage Equipment			6.55%	← 15 Year Amortization →		6.55%
397.00 Communication Equipment			6.67%	← 15 Year Amortization →		6.67%
398.00 Miscellaneous Equipment			6.67%	← 15 Year Amortization →		6.67%
Total Amortizable	6.41%		6.41%	6.41%		6.41%
Total General Plant	6.38%	-0.18%	6.20%	6.69%	-0.16%	6.53%
TOTAL CENTRAL-GULF SERVICE AREA	2.21%	0.38%	2.60%	2.33%	0.46%	2.79%
CENTRAL TEXAS SERVICE AREA						
TRANSMISSION PLANT						
367.00 Mains	1.38%	0.14%	1.52%	1.58%	0.17%	1.75%
369.00 Meas. and Reg. Station Equipment	3.44%		3.44%	1.66%	0.17%	1.83%
Total Transmission Plant	1.77%	0.11%	1.88%	1.60%	0.17%	1.77%
DISTRIBUTION PLANT						
375.10 Structures and Improvements	2.92%	0.11%	3.03%	1.78%	0.01%	1.79%
375.20 Other System Structures	2.47%	0.12%	2.59%	2.27%	0.11%	2.38%
376.00 Mains	1.38%	0.35%	1.73%	1.46%	0.41%	1.87%
376.90 Mains - Cathodic Protection	6.47%		6.47%	← 15 Year Amortization →		6.47%
378.00 Meas. and Reg. Station Equip. - General	1.66%	0.34%	2.00%	1.74%	0.36%	2.10%
379.00 Meas. and Reg. Station Equip. - City Gate	1.37%	0.15%	1.52%	1.47%	0.15%	1.62%
380.00 Services	1.47%	0.64%	2.11%	1.70%	0.81%	2.51%
381.00 Meters	3.11%	0.42%	3.53%	3.43%	0.50%	3.93%
383.00 House Regulators	1.84%	0.11%	1.95%	2.27%	0.20%	2.47%
385.00 Industrial Meas. and Reg. Station Equip.	1.45%	0.50%	1.95%	1.67%	0.47%	2.14%
386.00 Other Property on Customers' Premises	-1.17%	-0.03%	-1.20%	-0.67%	-0.03%	-0.70%
Total Distribution Plant	1.83%	0.42%	2.24%	1.98%	0.50%	2.48%

TEXAS GAS SERVICE - Central-Gulf Service Area Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2018)			Proposed (at 12/31/2018)		
	Investment	Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.20%	0.09%	2.29%	2.26%	0.09%	2.35%
392.00 Transportation Equipment	7.48%	-0.60%	6.88%	9.02%	-0.55%	8.47%
396.00 Power Operated Equipment	4.04%	-0.34%	3.70%	5.55%	-0.46%	5.09%
Total Depreciable	6.46%	-0.48%	5.98%	7.79%	-0.45%	7.34%
Amortizable						
391.10 Office Furniture and Fixtures			6.52%	← 15 Year Amortization →		6.52%
391.90 Computers and Electronic Equipment			4.48%	← 7 Year Amortization →		4.48%
393.00 Stores Equipment			6.67%	← 15 Year Amortization →		6.67%
394.00 Tools, Shop and Garage Equipment			6.57%	← 15 Year Amortization →		6.57%
397.00 Communication Equipment			6.67%	← 15 Year Amortization →		6.67%
398.00 Miscellaneous Equipment			6.67%	← 15 Year Amortization →		6.67%
Total Amortizable	6.33%		6.33%	6.33%		6.33%
Total General Plant	6.37%	-0.16%	6.21%	6.82%	-0.15%	6.67%
TOTAL CENTRAL TEXAS SERVICE AREA	2.14%	0.37%	2.52%	2.31%	0.45%	2.76%

TEXAS GAS SERVICE - Central-Gulf Service Area Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

	Current (at 12/31/2018)			Proposed (at 12/31/2018)		
Account Description	Investgment	Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
GULF COAST SERVICE AREA						
TRANSMISSION PLANT						
367.00 Mains						
369.00 Meas. and Reg. Station Equipment						
Total Transmission Plant						
DISTRIBUTION PLANT						
375.10 Structures and Improvements	1.80%	0.17%	1.97%	1.55%	0.06%	1.61%
375.20 Other System Structures	2.56%	0.26%	2.82%			
376.00 Mains	1.58%	0.41%	1.99%	1.54%	0.44%	1.98%
376.90 Mains - Cathodic Protection	3.63%		3.83%	← 15 Year Amortization →		3.83%
378.00 Meas. and Reg. Station Equip. - General	1.87%	0.38%	2.25%	1.82%	0.40%	2.22%
379.00 Meas. and Reg. Station Equip. - City Gate	1.82%	0.26%	2.08%	1.54%	0.27%	1.81%
380.00 Services	1.87%	0.86%	2.73%	1.82%	0.89%	2.71%
381.00 Meters	4.72%	0.12%	4.84%	4.07%	0.42%	4.49%
383.00 House Regulators	2.68%	0.02%	2.70%	2.73%	0.15%	2.88%
385.00 Industrial Meas. and Reg. Station Equip.	2.01%	0.41%	2.42%	1.81%	0.36%	2.17%
386.00 Other Property on Customers' Premises	4.89%	-0.28%	4.61%	7.54%	-0.23%	7.31%
Total Distribution Plant	2.20%	0.51%	2.72%	2.08%	0.58%	2.66%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.54%	0.11%	2.65%	2.41%	0.12%	2.53%
392.00 Transportation Equipment	10.06%	-0.99%	9.07%	9.33%	-0.76%	8.57%
396.00 Power Operated Equipment	8.52%	-1.14%	7.38%	7.25%	-0.89%	6.36%
Total Depreciable	5.99%	-0.43%	5.56%	5.52%	-0.31%	5.21%
Amortizable						
391.10 Office Furniture and Fixtures	6.49%		6.49%	← 15 Year Amortization →		6.49%
391.90 Computers and Electronic Equipment	13.17%		13.17%	← 7 Year Amortization →		13.17%
393.00 Stores Equipment	6.67%		6.67%	← 15 Year Amortization →		6.67%
394.00 Tools, Shop and Garage Equipment	6.45%		6.45%	← 15 Year Amortization →		6.45%
397.00 Communication Equipment	6.67%		6.67%	← 15 Year Amortization →		6.67%
398.00 Miscellaneous Equipment						
Total Amortizable	6.89%		6.89%	6.89%		6.89%
Total General Plant	6.39%	-0.24%	6.15%	6.13%	-0.17%	5.96%
TOTAL GULF COAST SERVICE AREA	2.60%	0.44%	3.05%	2.47%	0.51%	2.97%

TEXAS GAS SERVICE - Central-Gulf Service Area Statement B

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual Investment	Current 2019 Annualized Accrual Net Salvage	Current 2019 Annualized Accrual Total	Proposed 2019 Annualized Accrual Investment	Proposed 2019 Annualized Accrual Net Salvage	Proposed 2019 Annualized Accrual Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
CENTRAL-GULF SERVICE AREA								
TRANSMISSION PLANT								
367.00 Mains	$ 5,842,991	$ 80,633	$ 8,180	$ 88,813	$ 92,319	$ 9,933	$ 102,252	$ 13,439
369.00 Meas. and Reg. Station Equipment	1,368,821	47,087		47,087	22,722	2,327	25,049	(22,038)
Total Transmission Plant	$ 7,211,812	$ 127,721	$ 8,180	$ 135,901	$ 115,042	$ 12,260	$ 127,302	$ (8,599)
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 43,878	$ 1,050	$ 61	$ 1,111	$ 734	$ 15	$ 748	$ (363)
375.20 Other System Structures	916	23	1	24	21	1	22	(2)
376.00 Mains	302,302,483	4,242,348	1,079,231	5,321,579	4,441,846	1,250,026	5,691,872	370,293
376.90 Mains - Cathodic Protection	26,596,184	1,653,740		1,658,360	1,658,360		1,658,360	
378.00 Meas. and Reg. Station Equip. - General	12,531,394	211,801	43,327	255,128	219,486	45,833	265,319	10,192
379.00 Meas. and Reg. Station Equip. - City Gate	2,384,908	36,705	4,563	41,268	35,685	4,652	40,338	(930)
380.00 Services	170,927,490	2,641,725	1,164,936	3,806,661	2,944,495	1,410,331	4,354,825	548,165
381.00 Meters	62,721,893	2,141,120	227,941	2,369,061	2,227,075	304,145	2,531,220	162,160
383.00 House Regulators	8,774,632	176,258	8,066	184,324	207,292	16,668	223,960	39,636
385.00 Industrial Meas. and Reg. Station Equip.	13,146,120	207,813	62,967	270,780	223,839	58,409	282,248	11,468
386.00 Other Property on Customers' Premises	1,063,249	(8,113)	(497)	(8,610)	(1,261)	(462)	(1,723)	6,887
Total Distribution Plant	$ 600,493,147	$ 11,304,469	$ 2,590,594	$ 13,899,684	$ 11,957,571	$ 3,089,619	$ 15,047,190	$ 1,147,506
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 4,549,543	$ 109,399	$ 4,642	$ 114,042	$ 106,927	$ 4,916	$ 111,843	$ (2,199)
392.00 Transportation Equipment	12,188,165	964,118	(81,056)	883,061	1,105,674	(71,304)	1,034,370	151,309
396.00 Power Operated Equipment	1,542,948	82,682	(8,879)	73,803	93,355	(9,051)	84,304	10,501
Total Depreciable	$ 18,280,656	$ 1,156,200	$ (85,294)	$ 1,070,906	$ 1,305,955	$ (75,438)	$ 1,230,517	$ 159,611
Amortizable								
391.10 Office Furniture and Fixtures	$ 991,255	$ 64,616	$ -	$ 64,616	$ 64,616	$ -	$ 64,616	$ -
391.90 Computers and Electronic Equipment	3,857,179	189,019		189,019	189,019		189,019	
393.00 Stores Equipment	8,810	587		587	587		587	
394.00 Tools, Shop and Garage Equipment	7,085,223	463,978		463,978	463,978		463,978	
397.00 Communication Equipment	18,111,898	1,207,246		1,207,246	1,207,246		1,207,246	
398.00 Miscellaneous Equipment	130,360	8,691		8,691	8,691		8,691	
Total Amortizable	$ 30,184,725	$ 1,934,137	$ -	$ 1,934,137	$ 1,934,137	$ -	$ 1,934,137	$ -
Total General Plant	$ 48,465,381	$ 3,090,336	$ (85,294)	$ 3,005,043	$ 3,240,092	$ (75,438)	$ 3,164,654	$ 159,611
TOTAL CENTRAL-GULF SERVICE AREA	$ 656,170,340	$ 14,522,526	$ 2,513,481	$ 17,040,628	$ 15,312,704	$ 3,026,441	$ 18,339,145	$ 1,298,518

TEXAS GAS SERVICE - Central-Gulf Service Area
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual Investment	Current 2019 Annualized Accrual Net Salvage	Current 2019 Annualized Accrual Total	Proposed 2019 Annualized Accrual Investment	Proposed 2019 Annualized Accrual Net Salvage	Proposed 2019 Annualized Accrual Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
CENTRAL TEXAS SERVICE AREA								
TRANSMISSION PLANT								
367.00 Mains	$ 5,842,991	$ 80,633	$ 8,180	$ 88,813	$ 92,319	$ 9,933	$ 102,252	$ 13,439
369.00 Meas. and Reg. Station Equipment	1,368,821	47,087		47,087	22,722	2,327	25,049	(22,038)
Total Transmission Plant	$ 7,211,812	$ 127,721	$ 8,180	$ 135,901	$ 115,042	$ 12,260	$ 127,302	$ (8,599)
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 23,247	$ 679	$ 26	$ 704	$ 414	$ 2	$ 416	$ (288)
375.20 Other System Structures	916	23	1	24	21	1	22	(2)
376.00 Mains	267,015,686	3,684,816	934,555	4,619,371	3,898,429	1,094,764	4,993,193	373,822
376.90 Mains - Cathodic Protection	24,244,272	1,568,365		1,568,365	1,568,365		1,568,365	
378.00 Meas. and Reg. Station Equip. - General	10,731,479	178,143	36,487	214,630	186,728	38,633	225,361	10,731
379.00 Meas. and Reg. Station Equip. - City Gate	1,489,030	20,400	2,234	22,633	21,889	2,234	24,122	1,489
380.00 Services	138,654,767	2,038,225	887,391	2,925,616	2,357,131	1,123,104	3,480,235	554,619
381.00 Meters	50,891,528	1,582,727	213,744	1,796,471	1,745,579	254,458	2,000,037	203,566
383.00 House Regulators	7,012,117	129,023	7,713	136,736	159,175	14,024	173,199	36,463
385.00 Industrial Meas. and Reg. Station Equip.	10,075,723	146,098	50,379	196,477	168,265	47,356	215,620	19,144
386.00 Other Property on Customers' Premises	991,840	(11,605)	(298)	(11,902)	(6,645)	(298)	(6,943)	4,959
Total Distribution Plant	$ 511,130,605	$ 9,336,893	$ 2,132,231	$ 11,469,125	$ 10,099,350	$ 2,574,278	$ 12,673,628	$ 1,204,504
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 1,811,483	$ 39,853	$ 1,630	$ 41,483	$ 40,940	$ 1,630	$ 42,570	$ 1,087
392.00 Transportation Equipment	10,155,493	759,631	(60,933)	698,698	916,025	(55,855)	860,170	161,472
396.00 Power Operated Equipment	1,088,765	43,986	(3,702)	40,284	60,426	(5,008)	55,418	15,134
Total Depreciable	$ 13,055,741	$ 843,470	$ (63,004)	$ 780,465	$ 1,017,391	$ (59,233)	$ 958,158	$ 177,693
Amortizable								
391.10 Office Furniture and Fixtures	$ 890,291	$ 58,060	$ -	$ 58,060	$ 58,060		$ 58,060	$ -
391.90 Computers and Electronic Equipment	3,670,450	164,432		164,432	164,432		164,432	
393.00 Stores Equipment	5,387	359		359	359		359	
394.00 Tools, Shop and Garage Equipment	5,924,999	389,176		389,176	389,176		389,176	
397.00 Communication Equipment	15,368,189	1,024,367		1,024,367	1,024,367		1,024,367	
398.00 Miscellaneous Equipment	130,360	8,691		8,691	8,691		8,691	
Total Amortizable	$ 25,989,676	$ 1,645,084	$ -	$ 1,645,084	$ 1,645,084		$ 1,645,084	$ -
Total General Plant	$ 39,045,417	$ 2,488,554	$ (63,004)	$ 2,425,550	$ 2,662,476	$ (59,233)	$ 2,603,243	$ 177,693
TOTAL CENTRAL TEXAS SERVICE AREA	$ 557,387,834	$ 11,953,168	$ 2,077,407	$ 14,030,575	$ 12,876,868	$ 2,527,305	$ 15,404,173	$ 1,373,597

TEXAS GAS SERVICE - Central-Gulf Service Area Statement B

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual Investment	Current 2019 Annualized Accrual Net Salvage	Current 2019 Annualized Accrual Total	Proposed 2019 Annualized Accrual Investment	Proposed 2019 Annualized Accrual Net Salvage	Proposed 2019 Annualized Accrual Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
GULF COAST SERVICE AREA								
TRANSMISSION PLANT								
367.00 Mains	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
369.00 Meas. and Reg. Station Equipment								
Total Transmission Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 20,631	$ 371	$ 35	$ 406	$ 320	$ 12	$ 332	$ (74)
375.20 Other System Structures								
376.00 Mains	35,286,797	557,531	144,676	702,207	543,417	155,262	698,679	(3,529)
376.90 Mains - Cathodic Protection	2,351,912	85,374		89,995	89,995		89,995	
378.00 Meas. and Reg. Station Equip. - General	1,799,915	33,658	6,840	40,498	32,758	7,200	39,958	(540)
379.00 Meas. and Reg. Station Equip. - City Gate	895,878	16,305	2,329	18,634	13,797	2,419	16,215	(2,419)
380.00 Services	32,272,723	603,500	277,545	881,045	587,364	287,227	874,591	(6,455)
381.00 Meters	11,830,365	558,393	14,196	572,590	481,496	49,688	531,183	(41,406)
383.00 House Regulators	1,762,515	47,235	353	47,588	48,117	2,644	50,760	3,173
385.00 Industrial Meas. and Reg. Station Equip.	3,070,397	61,715	12,589	74,304	55,574	11,053	66,628	(7,676)
386.00 Other Property on Customers' Premises	71,409	3,492	(200)	3,292	5,384	(164)	5,220	1,928
Total Distribution Plant	$ 89,362,542	$ 1,967,576	$ 458,363	$ 2,430,559	$ 1,858,221	$ 515,341	$ 2,373,561	$ (56,998)
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 2,738,060	$ 69,547	$ 3,012	$ 72,559	$ 65,987	$ 3,286	$ 69,273	$ (3,286)
392.00 Transportation Equipment	2,032,672	204,487	(20,123)	184,363	189,648	(15,448)	174,200	(10,163)
396.00 Power Operated Equipment	454,183	38,696	(5,178)	33,519	32,928	(4,042)	28,886	(4,633)
Total Depreciable	$ 5,224,915	$ 312,730	$ (22,289)	$ 290,441	$ 288,564	$ (16,205)	$ 272,359	$ (18,082)
Amortizable								
391.10 Office Furniture and Fixtures	$ 100,964	$ 6,557	$ -	$ 6,557	$ 6,557		$ 6,557	$ -
391.90 Computers and Electronic Equipment	186,729	24,587		24,587	24,587		24,587	
393.00 Stores Equipment	3,423	228		228	228		228	
394.00 Tools, Shop and Garage Equipment	1,160,224	74,802		74,802	74,802		74,802	
397.00 Communication Equipment	2,743,709	182,879		182,879	182,879		182,879	
398.00 Miscellaneous Equipment								
Total Amortizable	$ 4,195,049	$ 289,052	$ -	$ 289,052	$ 289,052		$ 289,052	$ -
Total General Plant	$ 9,419,964	$ 601,782	$ (22,289)	$ 579,493	$ 577,616	$ (16,205)	$ 561,411	$ (18,082)
TOTAL GULF COAST SERVICE AREA	$ 98,782,506	$ 2,569,358	$ 436,074	$ 3,010,052	$ 2,435,837	$ 499,136	$ 2,934,972	$ (75,080)

TEXAS GAS SERVICE - Central-Gulf Service Area Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2018

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
CENTRAL-GULF SERVICE AREA							
TRANSMISSION PLANT							
367.00 Mains	$ 5,842,991	$ 1,565,809	26.80%	$ 1,417,129	24.25%	$ 1,560,640	26.71%
369.00 Meas. and Reg. Station Equipment	1,368,821	43,447	3.17%	44,145	3.23%	48,616	3.55%
Total Transmission Plant	$ 7,211,812	$ 1,609,255	22.31%	$ 1,461,274	20.26%	$ 1,609,255	22.31%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 43,878	$ 28,418	64.77%	$ 31,209	71.13%	$ 33,403	76.13%
375.20 Other System Structures	916	3,741	408.42%	304	33.19%	359	39.24%
376.00 Mains	302,302,483	65,785,363	21.76%	51,481,194	17.03%	59,142,816	19.56%
376.90 Mains - Cathodic Protection	26,596,184	9,213,649	34.64%	12,105,429	45.52%	12,105,429	45.52%
378.00 Meas. and Reg. Station Equip. - General	12,531,394	2,625,949	20.95%	2,002,984	15.98%	2,308,671	18.42%
379.00 Meas. and Reg. Station Equip. - City Gate	2,384,908	664,120	27.85%	522,104	21.89%	565,402	23.71%
380.00 Services	170,927,490	35,571,978	20.81%	33,966,627	19.87%	38,754,239	22.67%
381.00 Meters	62,721,893	23,299,141	37.15%	21,650,810	34.52%	24,790,215	39.52%
383.00 House Regulators	8,774,632	3,930,495	44.79%	3,444,833	39.26%	3,941,259	44.92%
385.00 Industrial Meas. and Reg. Station Equip.	13,146,120	4,305,892	32.75%	3,360,341	25.56%	3,774,938	28.72%
386.00 Other Property on Customers' Premises	1,063,249	1,060,785	99.77%	918,724	86.41%	1,072,798	100.90%
Total Distribution Plant	$ 600,493,147	$ 146,489,530	24.39%	$ 129,484,559	21.56%	$ 146,489,530	24.39%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 4,549,543	$ 1,298,930	28.55%	$ 1,803,147	39.63%	$ 1,885,137	41.44%
392.00 Transportation Equipment	12,188,165	4,123,532	33.83%	3,049,075	25.02%	3,379,438	27.73%
396.00 Power Operated Equipment	1,542,948	788,561	51.11%	679,252	44.02%	750,726	48.66%
Total Depreciable	$ 18,280,656	$ 6,211,023	33.98%	$ 5,531,474	30.26%	$ 6,015,301	32.91%
Amortizable							
391.10 Office Furniture and Fixtures	$ 991,255	$ 489,804	49.41%	$ 506,195	51.07%	$ 506,195	51.07%
391.90 Computers and Electronic Equipment	3,857,179	3,426,144	88.83%	3,438,878	89.16%	3,438,878	89.16%
393.00 Stores Equipment	8,810	5,432	61.66%	4,596	52.17%	4,596	52.17%
394.00 Tools, Shop and Garage Equipment	7,085,223	2,365,656	33.39%	2,423,291	34.20%	2,423,291	34.20%
397.00 Communication Equipment	18,111,898	6,614,725	36.52%	6,723,635	37.12%	6,723,635	37.12%
398.00 Miscellaneous Equipment	130,360	69,811	53.55%	70,699	54.23%	70,699	54.23%
Total Amortizable	$ 30,184,725	$ 12,971,572	42.97%	$ 13,167,294	43.62%	$ 13,167,294	43.62%
Total General Plant	$ 48,465,381	$ 19,182,595	39.58%	$ 18,698,768	38.58%	$ 19,182,595	39.58%
TOTAL CENTRAL-GULF SERVICE AREA	$ 656,170,340	$ 167,281,380	25.49%	$ 149,644,601	22.81%	$ 167,281,380	25.49%

TEXAS GAS SERVICE - Central-Gulf Service Area Statement C
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2018

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
CENTRAL TEXAS SERVICE AREA							
TRANSMISSION PLANT							
367.00 Mains	$ 5,842,991	$ 1,565,809	26.80%	$ 1,417,129	24.25%	$ 1,560,640	26.71%
369.00 Meas. and Reg. Station Equipment	1,368,821	43,447	3.17%	44,145	3.23%	48,616	3.55%
Total Transmission Plant	$ 7,211,812	$ 1,609,255	22.31%	$ 1,461,274	20.26%	$ 1,609,255	22.31%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 23,247	$ 10,552	45.39%	$ 15,065	64.80%	$ 17,812	76.62%
375.20 Other System Structures	916	3,741	408.42%	304	33.19%	359	39.24%
376.00 Mains	267,015,686	58,096,288	21.76%	43,513,384	16.30%	51,447,762	19.27%
376.90 Mains - Cathodic Protection	24,244,272	7,453,276	30.74%	10,367,177	42.76%	10,367,177	42.76%
378.00 Meas. and Reg. Station Equip. - General	10,731,479	2,270,279	21.16%	1,728,049	16.10%	2,043,147	19.04%
379.00 Meas. and Reg. Station Equip. - City Gate	1,489,030	367,121	24.66%	282,445	18.97%	333,947	22.43%
380.00 Services	138,654,767	29,148,600	21.02%	27,474,768	19.82%	32,484,610	23.43%
381.00 Meters	50,891,528	20,066,920	39.43%	17,917,810	35.21%	21,185,004	41.63%
383.00 House Regulators	7,012,117	3,422,252	48.80%	2,836,654	40.45%	3,353,899	47.83%
385.00 Industrial Meas. and Reg. Station Equip.	10,075,723	3,297,843	32.73%	2,445,470	24.27%	2,891,385	28.70%
386.00 Other Property on Customers' Premises	991,840	1,001,057	100.93%	856,625	86.37%	1,012,825	102.12%
Total Distribution Plant	$ 511,130,605	$ 125,137,929	24.48%	$ 107,437,751	21.02%	$ 125,137,929	24.48%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 1,811,483	$ 377,297	20.83%	$ 678,718	37.47%	$ 773,835	42.72%
392.00 Transportation Equipment	10,155,493	3,236,389	31.87%	2,410,544	23.74%	2,748,361	27.06%
396.00 Power Operated Equipment	1,088,765	633,126	58.15%	523,024	48.04%	596,321	54.77%
Total Depreciable	$ 13,055,741	$ 4,246,812	32.53%	$ 3,612,286	27.67%	$ 4,118,517	31.55%
Amortizable							
391.10 Office Furniture and Fixtures	$ 890,291	$ 431,885	48.51%	$ 444,178	49.89%	$ 444,178	49.89%
391.90 Computers and Electronic Equipment	3,670,450	3,333,003	90.81%	3,311,635	90.22%	3,311,635	90.22%
393.00 Stores Equipment	5,387	2,256	41.88%	1,743	32.36%	1,743	32.36%
394.00 Tools, Shop and Garage Equipment	5,924,999	1,880,308	31.74%	1,938,127	32.71%	1,938,127	32.71%
397.00 Communication Equipment	15,368,189	5,715,099	37.19%	5,794,276	37.70%	5,794,276	37.70%
398.00 Miscellaneous Equipment	130,360	69,811	53.55%	70,699	54.23%	70,699	54.23%
Total Amortizable	$ 25,989,676	$ 11,432,362	43.99%	$ 11,560,658	44.48%	$ 11,560,658	44.48%
Total General Plant	$ 39,045,417	$ 15,679,175	40.16%	$ 15,172,944	38.86%	$ 15,679,175	40.16%
TOTAL CENTRAL TEXAS SERVICE AREA	$ 557,387,834	$ 142,426,359	25.55%	$ 124,071,969	22.26%	$ 142,426,359	25.55%

TEXAS GAS SERVICE - Central-Gulf Service Area

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2018

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
GULF COAST SERVICE AREA							
TRANSMISSION PLANT							
367.00 Mains	$ -	$ -		$ -		$ -	
369.00 Meas. and Reg. Station Equipment							
Total Transmission Plant	$ -	$ -		$ -		$ -	
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 20,631	$ 17,867	86.60%	$ 16,144	78.25%	$ 15,591	75.57%
375.20 Other System Structures							
376.00 Mains	35,286,797	7,689,074	21.79%	7,967,810	22.58%	7,695,054	21.81%
376.90 Mains - Cathodic Protection	2,351,912	1,760,374	74.85%	1,738,252	73.91%	$ 1,738,252	73.91%
378.00 Meas. and Reg. Station Equip. - General	1,799,915	355,669	19.76%	274,935	15.27%	265,523	14.75%
379.00 Meas. and Reg. Station Equip. - City Gate	895,878	296,999	33.15%	239,659	26.75%	231,455	25.84%
380.00 Services	32,272,723	6,423,378	19.90%	6,491,859	20.12%	6,269,628	19.43%
381.00 Meters	11,830,365	3,232,221	27.32%	3,733,000	31.55%	3,605,211	30.47%
383.00 House Regulators	1,762,515	508,243	28.84%	608,179	34.51%	587,360	33.33%
385.00 Industrial Meas. and Reg. Station Equip.	3,070,397	1,008,049	32.83%	914,871	29.80%	883,553	28.78%
386.00 Other Property on Customers' Premises	71,409	59,728	83.64%	62,099	86.96%	59,973	83.99%
Total Distribution Plant	$ 89,362,542	$ 21,351,601	23.89%	$ 22,046,808	24.67%	$ 21,351,601	23.89%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 2,738,060	$ 921,633	33.66%	$ 1,124,429	41.07%	$ 1,111,303	40.59%
392.00 Transportation Equipment	2,032,672	887,143	43.64%	638,531	31.41%	631,077	31.05%
396.00 Power Operated Equipment	454,183	155,435	34.22%	156,228	34.40%	154,404	34.00%
Total Depreciable	$ 5,224,915	$ 1,964,210	37.59%	$ 1,919,188	36.73%	$ 1,896,784	36.30%
Amortizable							
391.10 Office Furniture and Fixtures	$ 100,964	$ 57,919	57.37%	$ 62,017	61.42%	$ 62,017	61.42%
391.90 Computers and Electronic Equipment	186,729	93,142	49.88%	127,243	68.14%	127,243	68.14%
393.00 Stores Equipment	3,423	3,175	92.77%	2,853	83.35%	2,853	83.35%
394.00 Tools, Shop and Garage Equipment	1,160,224	485,348	41.83%	485,164	41.82%	485,164	41.82%
397.00 Communication Equipment	2,743,709	899,625	32.79%	929,359	33.87%	929,359	33.87%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 4,195,049	$ 1,539,210	36.69%	$ 1,606,636	38.30%	$ 1,606,636	38.30%
Total General Plant	$ 9,419,964	$ 3,503,420	37.19%	$ 3,525,824	37.43%	$ 3,503,420	37.19%
TOTAL GULF COAST SERVICE AREA	$ 98,782,506	$ 24,855,021	25.16%	$ 25,572,632	25.89%	$ 24,855,021	25.16%

TEXAS GAS SERVICE - Central-Gulf Service Area Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2018

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
CENTRAL-GULF SERVICE AREA							
TRANSMISSION PLANT							
367.00 Mains	$ 5,842,991	$ 1,463,952	25.05%	$ 96,688	1.65%	$ 1,560,640	26.71%
369.00 Meas. and Reg. Station Equipment	1,368,821	44,196	3.23%	4,420	0.32%	48,616	3.55%
Total Transmission Plant	$ 7,211,812	$ 1,508,148	20.91%	$ 101,107	1.40%	$ 1,609,255	22.31%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 43,878	$ 31,497	71.78%	$ 1,907	4.35%	$ 33,403	76.13%
375.20 Other System Structures	916	342	37.37%	17	1.87%	359	39.24%
376.00 Mains	302,302,483	64,924,407	21.48%	(5,781,591)	-1.91%	59,142,816	19.56%
376.90 Mains - Cathodic Protection	26,596,184	12,105,429	45.52%			12,105,429	45.52%
378.00 Meas. and Reg. Station Equip. - General	12,531,394	1,984,035	15.83%	324,636	2.59%	2,308,671	18.42%
379.00 Meas. and Reg. Station Equip. - City Gate	2,384,908	562,637	23.59%	2,765	0.12%	565,402	23.71%
380.00 Services	170,927,490	46,771,560	27.36%	(8,017,321)	-4.69%	38,754,239	22.67%
381.00 Meters	62,721,893	23,827,690	37.99%	962,526	1.53%	24,790,215	39.52%
383.00 House Regulators	8,774,632	3,891,374	44.35%	49,885	0.57%	3,941,259	44.92%
385.00 Industrial Meas. and Reg. Station Equip.	13,146,120	3,632,529	27.63%	142,409	1.08%	3,774,938	28.72%
386.00 Other Property on Customers' Premises	1,063,249	1,071,801	100.80%	997	0.09%	1,072,798	100.90%
Total Distribution Plant	$ 600,493,147	$ 158,803,300	26.45%	$ (12,313,770)	-2.05%	$ 146,489,530	24.39%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 4,549,543	$ 1,776,295	39.04%	$ 108,842	2.39%	$ 1,885,137	41.44%
392.00 Transportation Equipment	12,188,165	3,427,358	28.12%	(47,920)	-0.39%	3,379,438	27.73%
396.00 Power Operated Equipment	1,542,948	834,482	54.08%	(83,756)	-5.43%	750,726	48.66%
Total Depreciable	$ 18,280,656	$ 6,038,135	33.03%	$ (22,835)	-0.12%	$ 6,015,301	32.91%
Amortizable							
391.10 Office Furniture and Fixtures	$ 991,255	$ 506,195	51.07%	$ -		$ 506,195	51.07%
391.90 Computers and Electronic Equipment	3,857,179	3,438,878	89.16%			3,438,878	89.16%
393.00 Stores Equipment	8,810	4,596	52.17%			4,596	52.17%
394.00 Tools, Shop and Garage Equipment	7,085,223	2,423,291	34.20%			2,423,291	34.20%
397.00 Communication Equipment	18,111,898	6,723,635	37.12%			6,723,635	37.12%
398.00 Miscellaneous Equipment	130,360	70,699	54.23%			70,699	54.23%
Total Amortizable	$ 30,184,725	$ 13,167,294	43.62%	$ -		$ 13,167,294	43.62%
Total General Plant	$ 48,465,381	$ 19,205,429	39.63%	$ (22,835)	-0.05%	$ 19,182,595	39.58%
TOTAL CENTRAL-GULF SERVICE AREA	$ 656,170,340	$ 179,516,877	27.36%	$ (12,235,497)	-1.86%	$ 167,281,380	25.49%

TEXAS GAS SERVICE - Central-Gulf Service Area Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2018

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
CENTRAL TEXAS SERVICE AREA							
TRANSMISSION PLANT							
367.00 Mains	$ 5,842,991	$ 1,463,952	25.05%	$ 96,688	1.65%	$ 1,560,640	26.71%
369.00 Meas. and Reg. Station Equipment	1,368,821	44,196	3.23%	4,420	0.32%	48,616	3.55%
Total Transmission Plant	$ 7,211,812	$ 1,508,148	20.91%	$ 101,107	1.40%	$ 1,609,255	22.31%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 23,247	$ 16,697	71.82%	$ 1,115	4.80%	$ 17,812	76.62%
375.20 Other System Structures	916	342	37.37%	17	1.87%	359	39.24%
376.00 Mains	267,015,686	56,482,287	21.15%	(5,034,525)	-1.89%	51,447,762	19.27%
376.90 Mains - Cathodic Protection	24,244,272	10,367,177	42.76%			10,367,177	42.76%
378.00 Meas. and Reg. Station Equip. - General	10,731,479	1,739,120	16.21%	304,027	2.83%	2,043,147	19.04%
379.00 Meas. and Reg. Station Equip. - City Gate	1,489,030	308,867	20.74%	25,080	1.68%	333,947	22.43%
380.00 Services	138,654,767	38,497,130	27.76%	(6,012,520)	-4.34%	32,484,610	23.43%
381.00 Meters	50,891,528	20,520,703	40.32%	664,301	1.31%	21,185,004	41.63%
383.00 House Regulators	7,012,117	3,326,567	47.44%	27,332	0.39%	3,353,899	47.83%
385.00 Industrial Meas. and Reg. Station Equip.	10,075,723	2,890,676	28.69%	709	0.01%	2,891,385	28.70%
386.00 Other Property on Customers' Premises	991,840	1,012,183	102.05%	642	0.06%	1,012,825	102.12%
Total Distribution Plant	$ 511,130,605	$ 135,161,750	26.44%	$ (10,023,821)	-1.96%	$ 125,137,929	24.48%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 1,811,483	$ 724,213	39.98%	$ 49,622	2.74%	$ 773,835	42.72%
392.00 Transportation Equipment	10,155,493	2,809,939	27.67%	(61,578)	-0.61%	2,748,361	27.06%
396.00 Power Operated Equipment	1,088,765	670,195	61.56%	(73,873)	-6.79%	596,321	54.77%
Total Depreciable	$ 13,055,741	$ 4,204,346	32.20%	$ (85,829)	-0.66%	$ 4,118,517	31.55%
Amortizable							
391.10 Office Furniture and Fixtures	$ 890,291	$ 444,178	49.89%			$ 444,178	49.89%
391.90 Computers and Electronic Equipment	3,670,450	3,311,635	90.22%			3,311,635	90.22%
393.00 Stores Equipment	5,387	1,743	32.36%			1,743	32.36%
394.00 Tools, Shop and Garage Equipment	5,924,999	1,938,127	32.71%			1,938,127	32.71%
397.00 Communication Equipment	15,368,189	5,794,276	37.70%			5,794,276	37.70%
398.00 Miscellaneous Equipment	130,360	70,699	54.23%			70,699	54.23%
Total Amortizable	$ 25,989,676	$ 11,560,658	44.48%			$ 11,560,658	44.48%
Total General Plant	$ 39,045,417	$ 15,765,004	40.38%	$ (85,829)	-0.22%	$ 15,679,175	40.16%
TOTAL CENTRAL TEXAS SERVICE AREA	$ 557,387,834	$ 152,434,902	27.35%	$ (10,008,543)	-1.80%	$ 142,426,359	25.55%

TEXAS GAS SERVICE - Central-Gulf Service Area Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2018

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
GULF COAST SERVICE AREA							
TRANSMISSION PLANT							
367.00 Mains	$ -	$ -		$ -		$ -	
369.00 Meas. and Reg. Station Equipment							
Total Transmission Plant	$ -	$ -		$ -		$ -	
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 20,631	$ 14,800	71.74%	$ 791	3.84%	$ 15,591	75.57%
375.20 Other System Structures							
376.00 Mains	35,286,797	8,442,120	23.92%	(747,066)	-2.12%	7,695,054	21.81%
376.90 Mains - Cathodic Protection	2,351,912	1,738,252	73.91%			1,738,252	73.91%
378.00 Meas. and Reg. Station Equip. - General	1,799,915	244,915	13.61%	20,609	1.14%	265,523	14.75%
379.00 Meas. and Reg. Station Equip. - City Gate	895,878	253,770	28.33%	(22,315)	-2.49%	231,455	25.84%
380.00 Services	32,272,723	8,274,430	25.64%	(2,004,802)	-6.21%	6,269,628	19.43%
381.00 Meters	11,830,365	3,306,986	27.95%	298,225	2.52%	3,605,211	30.47%
383.00 House Regulators	1,762,515	564,806	32.05%	22,553	1.28%	587,360	33.33%
385.00 Industrial Meas. and Reg. Station Equip.	3,070,397	741,853	24.16%	141,700	4.62%	883,553	28.78%
386.00 Other Property on Customers' Premises	71,409	59,618	83.49%	355	0.50%	59,973	83.99%
Total Distribution Plant	$ 89,362,542	$ 23,641,550	26.46%	$ (2,289,949)	-2.56%	$ 21,351,601	23.89%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 2,738,060	$ 1,052,082	38.42%	$ 59,220	2.16%	$ 1,111,303	40.59%
392.00 Transportation Equipment	2,032,672	617,419	30.37%	13,658	0.67%	631,077	31.05%
396.00 Power Operated Equipment	454,183	164,287	36.17%	(9,883)	-2.18%	154,404	34.00%
Total Depreciable	$ 5,224,915	$ 1,833,789	35.10%	$ 62,995	1.21%	$ 1,896,784	36.30%
Amortizable							
391.10 Office Furniture and Fixtures	$ 100,964	$ 62,017	61.42%			$ 62,017	61.42%
391.90 Computers and Electronic Equipment	186,729	127,243	68.14%			127,243	68.14%
393.00 Stores Equipment	3,423	2,853	83.35%			2,853	83.35%
394.00 Tools, Shop and Garage Equipment	1,160,224	485,164	41.82%			485,164	41.82%
397.00 Communication Equipment	2,743,709	929,359	33.87%			929,359	33.87%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 4,195,049	$ 1,606,636	38.30%			$ 1,606,636	38.30%
Total General Plant	$ 9,419,964	$ 3,440,425	36.52%	$ 62,995	0.67%	$ 3,503,420	37.19%
TOTAL GULF COAST SERVICE AREA	$ 98,782,506	$ 27,081,975	27.42%	$ (2,226,954)	-2.25%	$ 24,855,021	25.16%

TEXAS GAS SERVICE - Central-Gulf Service Area Statement E

Average Net Salvage

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
CENTRAL-GULF SERVICE AREA									
TRANSMISSION PLANT									
367.00 Mains	$ 5,868,545	$ 25,554	$ 5,842,991	-234.6%	-10.0%	$ (59,950)	$ (584,299)	$ (644,249)	-11.0%
369.00 Meas. and Reg. Station Equipment	1,368,821		1,368,821		-10.0%		(136,882)	(136,882)	-10.0%
Total Transmission Plant	$ 7,237,366	$ 25,554	$ 7,211,812	-234.6%	-10.0%	$ (59,950)	$ (721,181)	$ (781,131)	-10.8%
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 75,076	$ 31,198	$ 43,878		-5.0%	$ -	$ (2,194)	$ (2,194)	-2.9%
375.20 Other System Structures	916		916		-5.0%		(46)	(46)	-5.0%
376.00 Mains	313,133,202	10,830,719	302,302,483	-214.9%	-20.0%	(23,276,603)	(60,460,497)	(83,737,100)	-26.7%
376.90 Mains - Cathodic Protection	33,887,945	7,291,761	26,596,184						
378.00 Meas. and Reg. Station Equip. - General	13,319,723	788,329	12,531,394	-30.9%	-20.0%	(243,489)	(2,506,279)	(2,749,768)	-20.6%
379.00 Meas. and Reg. Station Equip. - City Gate	2,444,725	59,817	2,384,908	-142.3%	-10.0%	(85,104)	(238,491)	(323,595)	-13.2%
380.00 Services	181,564,119	10,636,629	170,927,490	-288.8%	-30.0%	(30,713,560)	(51,278,247)	(81,991,807)	-45.2%
381.00 Meters	74,261,216	11,539,323	62,721,893	-28.4%	-10.0%	(3,276,875)	(6,272,189)	(9,549,065)	-12.9%
383.00 House Regulators	10,883,745	2,109,113	8,774,632	-16.7%	-5.0%	(353,171)	(438,732)	(791,902)	-7.3%
385.00 Industrial Meas. and Reg. Station Equip.	13,739,491	593,371	13,146,120	-135.2%	-20.0%	(802,343)	(2,629,224)	(3,431,567)	-25.0%
386.00 Other Property on Customers' Premises	1,311,364	248,115	1,063,249	4.8%		11,992		11,992	0.9%
Total Distribution Plant	$ 644,621,522	$ 44,128,375	$ 600,493,147	-133.1%	-20.6%	$ (58,739,153)	$ (123,825,898)	$ (182,565,051)	-28.3%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 5,110,740	$ 561,197	$ 4,549,543	1.2%	-5.0%	$ 6,661	$ (227,477)	$ (220,817)	-4.3%
392.00 Transportation Equipment	14,412,322	2,224,157	12,188,165	13.2%	5.0%	294,447	609,408	903,855	6.3%
396.00 Power Operated Equipment	1,825,349	282,401	1,542,948	8.5%	10.0%	24,019	154,295	178,314	9.8%
Total Depreciable	$ 21,348,411	$ 3,067,755	$ 18,280,656	10.6%	2.9%	$ 325,127	$ 536,226	$ 861,353	4.0%
Amortizable									
391.10 Office Furniture and Fixtures	$ 2,442,055	$1,450,800	$ 991,255			$ -	$ -		
391.90 Computers and Electronic Equipment	5,413,223	1,556,044	3,857,179						
393.00 Stores Equipment	97,889	89,079	8,810						
394.00 Tools, Shop and Garage Equipment	9,945,832	2,860,609	7,085,223						
397.00 Communication Equipment	19,807,600	1,695,702	18,111,898						
398.00 Miscellaneous Equipment	1,044,307	913,947	130,360						
Total Amortizable	$ 38,750,906	$ 8,566,181	$ 30,184,725			$ -	$ -		
Total General Plant	$ 60,099,317	$ 11,633,936	$ 48,465,381	2.8%	1.1%	$ 325,127	$ 536,226	$ 861,353	1.4%
TOTAL CENTRAL-GULF SERVICE AREA	$ 704,720,839	$ 55,762,311	$ 648,958,528	-104.8%	-19.0%	$ (58,414,027)	$ (123,289,672)	$ (181,703,699)	-25.8%

TEXAS GAS SERVICE - Central-Gulf Service Area
Average Net Salvage

Statement E

Account Description	Plant Investment Additions	Retirements	Survivors	Salvage Rate Realized	Future	Net Salvage Realized	Future	Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
CENTRAL TEXAS SERVICE AREA									
TRANSMISSION PLANT									
367.00 Mains	$ 5,868,545	$ 25,554	$ 5,842,991	-234.6%	-10.0%	$ (59,950)	$ (584,299)	$ (644,249)	-11.0%
369.00 Meas. and Reg. Station Equipment	1,368,821		1,368,821		-10.0%		(136,882)	(136,882)	-10.0%
Total Transmission Plant	$ 7,237,366	$ 25,554	$ 7,211,812	-234.6%	-10.0%	$ (59,950)	$ (721,181)	$ (781,131)	-10.8%
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 49,069	$ 25,822	$ 23,247		-5.0%		$ (1,162)	$ (1,162)	-2.4%
375.20 Other System Structures	916		916		-5.0%		(46)	(46)	-5.0%
376.00 Mains	274,634,314	7,618,628	267,015,686	-248.9%	-20.0%	(18,962,765)	(53,403,137)	(72,365,902)	-26.3%
376.90 Mains - Cathodic Protection	31,248,464	7,004,192	24,244,272						
378.00 Meas. and Reg. Station Equip. - General	11,307,392	575,913	10,731,479	-28.3%	-20.0%	(162,983)	(2,146,296)	(2,309,279)	-20.4%
379.00 Meas. and Reg. Station Equip. - City Gate	1,495,308	6,278	1,489,030	-96.0%	-10.0%	(6,027)	(148,903)	(154,930)	-10.4%
380.00 Services	144,610,180	5,955,413	138,654,767	-370.7%	-30.0%	(22,076,716)	(41,596,430)	(63,673,146)	-44.0%
381.00 Meters	58,568,115	7,676,587	50,891,528	-36.9%	-10.0%	(2,832,661)	(5,089,153)	(7,921,813)	-13.5%
383.00 House Regulators	8,429,132	1,417,015	7,012,117	-21.7%	-5.0%	(307,492)	(350,606)	(658,098)	-7.8%
385.00 Industrial Meas. and Reg. Station Equip.	10,508,443	432,720	10,075,723	-176.1%	-20.0%	(762,020)	(2,015,145)	(2,777,165)	-26.4%
386.00 Other Property on Customers' Premises	1,099,386	107,546	991,840	3.7%		3,979		3,979	0.4%
Total Distribution Plant	$ 541,950,719	$ 30,820,114	$ 511,130,605	-146.4%	-20.5%	$ (45,106,685)	$ (104,750,878)	$ (149,857,562)	-27.7%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 2,089,445	$ 277,962	$ 1,811,483	2.6%	-5.0%	$ 7,227	$ (90,574)	$ (83,347)	-4.0%
392.00 Transportation Equipment	11,998,149	1,842,656	10,155,493	10.7%	5.0%	197,164	507,775	704,939	5.9%
396.00 Power Operated Equipment	1,316,994	228,229	1,088,765	3.0%	10.0%	6,847	108,877	115,723	8.8%
Total Depreciable	$ 15,404,588	$ 2,348,847	$ 13,055,741	9.0%	4.0%	$ 211,238	$ 526,077	$ 737,315	4.8%
Amortizable									
391.10 Office Furniture and Fixtures	$1,827,190	$936,899	$890,291						
391.90 Computers and Electronic Equipment	4,783,194	1,112,744	3,670,450						
393.00 Stores Equipment	81,351	75,964	5,387						
394.00 Tools, Shop and Garage Equipment	7,807,626	1,882,627	5,924,999						
397.00 Communication Equipment	16,346,350	978,161	15,368,189						
398.00 Miscellaneous Equipment	1,044,307	913,947	130,360						
Total Amortizable	$ 31,890,018	$ 5,900,342	$ 25,989,676						
Total General Plant	$ 47,294,606	$ 8,249,189	$ 39,045,417	2.6%	1.3%	$ 211,238	$ 526,077	$ 737,315	1.6%
TOTAL CENTRAL TEXAS SERVICE AREA	$ 596,482,691	$ 39,094,857	$ 557,387,834	-115.0%	-18.8%	$ (44,955,397)	$ (104,945,982)	$ (149,901,378)	-25.1%

TEXAS GAS SERVICE - Central-Gulf Service Area
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GULF COAST SERVICE AREA									
TRANSMISSION PLANT									
367.00 Mains	$ -	$ -	$ -			$ -	$ -	$ -	
369.00 Meas. and Reg. Station Equipment									
Total Transmission Plant	$ -	$ -	$ -			$ -	$ -	$ -	
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 26,007	$ 5,376	$ 20,631		-5.0%		$ (1,032)	$ (1,032)	-4.0%
375.20 Other System Structures									
376.00 Mains	38,498,888	3,212,091	35,286,797	-134.3%	-20.0%	(4,313,838)	(7,057,359)	(11,371,198)	-29.5%
376.90 Mains - Cathodic Protection	2,639,481	287,569	2,351,912						
378.00 Meas. and Reg. Station Equip. - General	2,012,331	212,416	1,799,915	-37.9%	-20.0%	(80,506)	(359,983)	(440,489)	-21.9%
379.00 Meas. and Reg. Station Equip. - City Gate	949,417	53,539	895,878	-147.7%	-10.0%	(79,077)	(89,588)	(168,665)	-17.8%
380.00 Services	36,953,939	4,681,216	32,272,723	-184.5%	-30.0%	(8,636,844)	(9,681,817)	(18,318,660)	-49.6%
381.00 Meters	15,693,101	3,862,736	11,830,365	-11.5%	-10.0%	(444,215)	(1,183,037)	(1,627,251)	-10.4%
383.00 House Regulators	2,454,613	692,098	1,762,515	-6.6%	-5.0%	(45,678)	(88,126)	(133,804)	-5.5%
385.00 Industrial Meas. and Reg. Station Equip.	3,231,048	160,651	3,070,397	-25.1%	-20.0%	(40,323)	(614,079)	(654,403)	-20.3%
386.00 Other Property on Customers' Premises	211,978	140,569	71,409	5.7%		8,012		8,012	3.8%
Total Distribution Plant	$ 102,670,803	$ 13,308,261	$ 89,362,542	-102.4%	-21.3%	$ (13,632,469)	$ (19,075,020)	$ (32,707,489)	-31.9%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 3,021,295	$ 283,235	$ 2,738,060	-0.2%	-5.0%	$ (566)	$ (136,903)	$ (137,469)	-4.6%
392.00 Transportation Equipment	2,414,173	381,501	2,032,672	25.5%	5.0%	97,283	101,634	198,916	8.2%
396.00 Power Operated Equipment	508,355	54,172	454,183	31.7%	10.0%	17,173	45,418	62,591	12.3%
Total Depreciable	$ 5,943,823	$ 718,908	$ 5,224,915	15.8%	0.2%	$ 113,889	$ 10,149	$ 124,038	2.1%
Amortizable									
391.10 Office Furniture and Fixtures	$614,865	$513,901	$100,964						
391.90 Computers and Electronic Equipment	630,029	443,300	186,729						
393.00 Stores Equipment	16,538	13,115	3,423						
394.00 Tools, Shop and Garage Equipment	2,138,206	977,982	1,160,224						
397.00 Communication Equipment	3,461,250	717,541	2,743,709						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 6,860,888	$ 2,665,839	$ 4,195,049						
Total General Plant	$ 12,804,711	$ 3,384,747	$ 9,419,964	3.4%	0.1%	$ 113,889	$ 10,149	$ 124,038	1.0%
TOTAL GULF COAST SERVICE AREA	$ 115,475,514	$ 16,693,008	$ 98,782,506	-81.0%	-19.3%	$ (13,518,580)	$ (19,064,871)	$ (32,583,451)	-28.2%

TEXAS GAS SERVICE - Central-Gulf Service Area
Current and Proposed Parameters
Vintage Group Procedure

Statement F

	Current Parameters						Proposed Parameters (at December 31, 2018)					
Account Description	P-Life/ AYFR	Curve Shape	Avg. Life	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
CENTRAL-GULF SERVICE AREA												
TRANSMISSION PLANT												
367.00 Mains	60.00	R1			-11.0	-10.0	60.00	R1	61.58	47.57	-11.0	-10.0
369.00 Meas. and Reg. Station Equipment	60.00	R1			-10.0	-10.0	60.00	R1	60.03	58.27	-10.0	-10.0
Total Transmission Plant									61.28	49.64	-10.8	-10.0
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4			-2.9	-5.0	40.00	R4	50.66	16.66	-2.9	-5.0
375.20 Other System Structures	40.00	R2			-5.0	-5.0	40.00	R2	40.37	27.61	-5.0	-5.0
376.00 Mains	65.00	R1.5			-26.7	-20.0	65.00	R1.5	65.65	53.38	-26.7	-20.0
376.90 Mains - Cathodic Protection	15.00	SQ					15.00	SQ	15.00	8.45		
378.00 Meas. and Reg. Station Equip. - General	55.00	R0.5			-20.6	-20.0	55.00	R0.5	55.67	48.01	-20.6	-20.0
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5			-13.2	-10.0	65.00	R1.5	65.67	51.24	-13.2	-10.0
380.00 Services	59.00	S0.5			-45.2	-30.0	55.00	R2	55.54	42.17	-45.2	-30.0
381.00 Meters	25.00	R2.5			-12.9	-10.0	25.00	R2.5	26.10	17.45	-12.9	-10.0
383.00 House Regulators	35.00	R3			-7.3	-5.0	35.00	R3	38.43	23.55	-7.3	-5
385.00 Industrial Meas. and Reg. Station Equip.	55.00	R1			-25.0	-20.0	55.00	R1	56.34	42.57	-25.0	-20.0
386.00 Other Property on Customers' Premises	20.00	S3			0.9		20.00	S3	21.67	2.96	0.9	
Total Distribution Plant									47.54	36.47	-28.3	-20.6
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	40.00	R1.5			-4.3	-5.0	40.00	R1.5	41.35	25.90	-4.3	-5.0
392.00 Transportation Equipment	10.00	L0			6.3	5.0	10.00	L0	10.62	7.93	6.3	5.0
396.00 Power Operated Equipment	13.00	L2			9.8	10.0	13.00	L2	14.68	7.51	9.8	10.0
Total Depreciable									13.41	9.35	4.0	2.9
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ					15.00	SQ	15.00	7.34		
391.90 Computers and Electronic Equipment	7.00	SQ					7.00	SQ	7.00	1.70		
393.00 Stores Equipment	15.00	SQ					15.00	SQ	15.00	7.18		
394.00 Tools, Shop and Garage Equipment	15.00	SQ					15.00	SQ	15.00	9.87		
397.00 Communication Equipment	15.00	SQ					15.00	SQ	15.00	9.43		
398.00 Miscellaneous Equipment	15.00	SQ					15.00	SQ	15.00	6.86		
Total Amortizable									13.09	7.60		
Total General Plant									13.21	8.25	1.4	1.1
TOTAL CENTRAL-GULF SERVICE AREA									39.96	30.26	-25.8	-19.0

TEXAS GAS SERVICE - Central-Gulf Service Area
Current and Proposed Parameters
Vintage Group Procedure

Statement F

Account Description	Current Parameters						Proposed Parameters (at December 31, 2018)					
	P-Life/ AYFR	Curve Shape	Avg. Life	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
CENTRAL TEXAS SERVICE AREA												
TRANSMISSION PLANT												
367.00 Mains	60.00	R1	61.71	46.12	-10.0	-10.0	60.00	R1	61.58	47.57	-11.0	-10.0
369.00 Meas. and Reg. Station Equipment	60.00	R1	61.71	46.12	-10.0	-10.0	60.00	R1	60.03	58.27	-10.0	-10.0
Total Transmission Plant									61.28	49.64	-10.8	-10.0
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	40.10	23.40	-2.8	-5.0	40.00	R4	40.38	15.85	-2.4	-5.0
375.20 Other System Structures	40.00	R2	40.01	38.70	-5.0	-5.0	40.00	R2	40.37	27.61	-5.0	-5.0
376.00 Mains	65.00	R1.5	65.72	53.01	-23.6	-20.0	65.00	R1.5	65.62	53.88	-26.3	-20.0
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	10.37			15.00	SQ	15.00	8.68		
378.00 Meas. and Reg. Station Equip. - General	55.00	R0.5	55.95	47.38	-20.8	-20.0	55.00	R0.5	55.74	48.10	-20.4	-20.0
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5	65.55	53.26	-10.5	-10.0	65.00	R1.5	65.55	54.05	-10.4	-10.0
380.00 Services	59.00	S0.5	59.58	46.34	-38.7	-30.0	55.00	R2	55.53	42.49	-44.0	-30.0
381.00 Meters	25.00	R2.5	26.90	18.69	-12.4	-10.0	25.00	R2.5	26.39	17.39	-13.5	-10.0
383.00 House Regulators	35.00	R3	39.89	24.43	-5.7	-5.0	35.00	R3	38.73	23.19	-7.8	-5.0
385.00 Industrial Meas. and Reg. Station Equip.	55.00	R1	56.74	40.50	-28.2	-20.0	55.00	R1	56.46	42.76	-26.4	-20.0
386.00 Other Property on Customers' Premises	20.00	S3	20.56	4.41	0.4		20.00	S3	22.21	3.04	0.4	
Total Distribution Plant									47.63	36.84	-27.7	-20.5
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	40.00	R1.5	40.95	27.21	-4.4	-5.0	40.00	R1.5	40.81	26.50	-4.0	-5.0
392.00 Transportation Equipment	10.00	L0	11.07	7.39	7.0	5.0	10.00	L0	10.59	8.02	5.9	5.0
396.00 Power Operated Equipment	13.00	L2	14.60	6.96	8.1	10.0	13.00	L2	15.04	6.92	8.8	10.0
Total Depreciable									12.14	8.71	4.8	4.0
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	10.20			15.00	SQ	15.00	7.52		
391.90 Computers and Electronic Equipment	7.00	SQ	7.00	3.42			7.00	SQ	7.00	1.67		
393.00 Stores Equipment	15.00	SQ	15.00	13.32			15.00	SQ	15.00	10.15		
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	10.47			15.00	SQ	15.00	10.09		
397.00 Communication Equipment	15.00	SQ	15.00	11.57			15.00	SQ	15.00	9.34		
398.00 Miscellaneous Equipment	15.00	SQ	15.00	9.50			15.00	SQ	15.00	6.86		
Total Amortizable									12.92	7.42		
Total General Plant							0.07		12.64	7.87	1.6	1.3
TOTAL CENTRAL TEXAS SERVICE AREA									39.99	30.53	-25.1	-18.8

TEXAS GAS SERVICE - Central-Gulf Service Area
Current and Proposed Parameters
Vintage Group Procedure

Statement F

	Current Parameters						Proposed Parameters (at December 31, 2018)					
Account Description	P-Life/ AYFR	Curve Shape	Avg. Life	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
GULF COAST SERVICE AREA												
TRANSMISSION PLANT												
367.00 Mains												
369.00 Meas. and Reg. Station Equipment												
Total Transmission Plant												
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	53.52	30.27	-8.8	-10.0	40.00	R4	71.04	18.27	-4.0	-5.0
375.20 Other System Structures			40.03	36.19	-10	-10.0						
376.00 Mains	65.00	R1.5	65.98	49.93	-27.3	-20.0	65.00	R1.5	65.88	49.56	-29.5	-20.0
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	7.65			15.00	SQ	15.00	6.12		
378.00 Meas. and Reg. Station Equip. - General	55.00	R1	55.46	44.56	-20.0	-20.0	55.00	R0.5	55.29	47.50	-21.9	-20.0
379.00 Meas. and Reg. Station Equip. - City Gate	55.00	R1.5	55.97	39.61	-15.1	-10.0	65.00	R1.5	65.87	46.55	-17.8	-10.0
380.00 Services	55.00	R2	55.78	41.04	-49.1	-30.0	55.00	R2	55.56	40.81	-49.6	-30.0
381.00 Meters	22.00	R2.5	22.35	17.63	-2.9		25.00	R2.5	24.91	17.70	-10.4	-10.0
383.00 House Regulators	35.00	R4	38.14	26.41	-0.8		35.00	R3	37.28	24.91	-5.5	-5.0
385.00 Industrial Meas. and Reg. Station Equip.	50.00	R1	51.10	38.00	-20.3	-20.0	55.00	R1	55.96	41.96	-20.3	-20.0
386.00 Other Property on Customers' Premises	25.00	S3	18.35	6.22	4.9		20.00	S3	16.16	2.19	3.8	
Total Distribution Plant									47.00	34.34	-31.9	-21.3
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	40.00	R1.5	41.19	26.38	-4.6	-5.0	40.00	R1.5	41.72	25.50	-4.6	-5.0
392.00 Transportation Equipment	10.00	L0	10.42	7.73	10.9	5.0	10.00	L0	10.77	7.46	8.2	5.0
396.00 Power Operated Equipment	12.00	L2	12.79	7.82	14.7	10.0	13.00	L2	13.88	8.80	12.3	10.0
Total Depreciable									18.20	11.74	2.1	0.2
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	6.42			15.00	SQ	15.00	5.79		
391.90 Computers and Electronic Equipment	7.00	SQ	7.00	3.55			7.00	SQ	7.00	2.23		
393.00 Stores Equipment	15.00	SQ	15.00	2.82			15.00	SQ	15.00	2.50		
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	8.41			15.00	SQ	15.00	8.73		
397.00 Communication Equipment	15.00	SQ	15.00	11.51			15.00	SQ	15.00	9.92		
398.00 Miscellaneous Equipment												
Total Amortizable									14.27	8.81		
Total General Plant									16.21	10.26	1.0	0.1
TOTAL GULF COAST SERVICE AREA									39.80	28.70	-28.2	-19.3

Statements A through F

TEXAS GAS SERVICE - TGS Division
Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement A

Account Description	Current (at 12/31/2018) Investment	Net Salvage	Total	Proposed (at 12/31/2018) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.63%	0.14%	2.77%	2.49%	0.10%	2.59%
Total Depreciable	2.63%	0.14%	2.77%	2.49%	0.10%	2.59%
Amortizable						
391.10 Office Furniture and Fixtures	6.31%		6.31%	← 15 Year Amortization →		6.31%
391.90 Computers and Electronic Equipment	11.97%		11.97%	← 7 Year Amortization →		11.97%
394.00 Tools, Shop and Garage Equipment	6.67%		6.67%	← 15 Year Amortization →		6.67%
397.00 Communication Equipment	6.12%		6.12%	← 15 Year Amortization →		6.12%
398.00 Miscellaneous Equipment				← 0 Year Amortization →		
Total Amortizable	10.01%		10.01%	10.01%		10.01%
Total General Plant	9.90%	0.00%	9.90%	9.90%		9.90%
TOTAL TGS DIVISION	9.90%	0.00%	9.90%	9.90%		9.90%

TEXAS GAS SERVICE - TGS Division Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/18 Investment	Current 2019 Annualized Accrual			Proposed 2019 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
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 74,162	$ 1,950	$ 104	$ 2,054	$ 1,847	$ 74	$ 1,921	$ (133)
Total Depreciable	$ 74,162	$ 1,950	$ 104	$ 2,054	$ 1,847	$ 74	$ 1,921	$ (133)
Amortizable								
391.10 Office Furniture and Fixtures	$ 491,087	$ 30,975	$ -	$ 30,975	$ 30,975		$ 30,975	$ -
391.90 Computers and Electronic Equipment	3,262,983	390,558		390,558	390,558		390,558	
394.00 Tools, Shop and Garage Equipment	20,328	1,355		1,355	1,355		1,355	
397.00 Communication Equipment	1,163,252	71,216		71,216	71,216		71,216	
398.00 Miscellaneous Equipment								
Total Amortizable	$ 4,937,650	$ 494,104	$ -	$ 494,104	$ 494,104		$ 494,104	$ -
Total General Plant	$ 5,011,812	$ 496,054	$ 104	$ 496,158	$ 495,950	$ 74	$ 496,025	$ (133)
TOTAL TGS DIVISION	$ 5,011,812	$ 496,054	$ 104	$ 496,158	$ 495,950	$ 74	$ 496,025	$ (133)

TEXAS GAS SERVICE - TGS Division
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2018

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
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 74,162	$ 915,534	1234.51%	$ 10,782	14.54%	$ 10,782	14.54%
Total Depreciable	$ 74,162	$ 915,534	1234.51%	$ 10,782	14.54%	$ 10,782	14.54%
Amortizable							
391.10 Office Furniture and Fixtures	$ 491,087	$ 241,551	49.19%	$ 305,729	62.26%	$ 305,729	62.26%
391.90 Computers and Electronic Equipment	3,262,983	1,441,121	44.17%	2,281,594	69.92%	2,281,594	69.92%
394.00 Tools, Shop and Garage Equipment	20,328	8,434	41.49%	7,992	39.32%	7,992	39.32%
397.00 Communication Equipment	1,163,252	784,929	67.48%	785,741	67.55%	785,741	67.55%
398.00 Miscellaneous Equipment		269					
Total Amortizable	$ 4,937,650	$ 2,476,304	50.15%	$ 3,381,056	68.48%	$ 3,381,056	68.48%
Total General Plant	$ 5,011,812	$ 3,391,838	67.68%	$ 3,391,838	67.68%	$ 3,391,838	67.68%
TOTAL TGS DIVISION	$ 5,011,812	$ 3,391,838	67.68%	$ 3,391,838	67.68%	$ 3,391,838	67.68%

TEXAS GAS SERVICE - TGS Division
Depreciation Reserve Components
Redistributed Reserve
December 31, 2018

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
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 74,162	$ 9,654	13.02%	$ 1,128	1.52%	$ 10,782	14.54%
Total Depreciable	$ 74,162	$ 9,654	13.02%	$ 1,128	1.52%	$ 10,782	14.54%
Amortizable							
391.10 Office Furniture and Fixtures	$ 491,087	$ 305,729	62.26%			$ 305,729	62.26%
391.90 Computers and Electronic Equipment	3,262,983	2,281,594	69.92%			2,281,594	69.92%
394.00 Tools, Shop and Garage Equipment	20,328	7,992	39.32%			7,992	39.32%
397.00 Communication Equipment	1,163,252	785,741	67.55%			785,741	67.55%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 4,937,650	$ 3,381,056	68.48%			$ 3,381,056	68.48%
Total General Plant	$ 5,011,812	$ 3,390,710	67.65%	$ 1,128	0.02%	$ 3,391,838	67.68%
TOTAL TGS DIVISION	$ 5,011,812	$ 3,390,710	67.65%	$ 1,128	0.02%	$ 3,391,838	67.68%

TEXAS GAS SERVICE - TGS Division
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 93,476	$ 19,314	$ 74,162		-5.0%	$ -	$ (3,708)	$ (3,708)	-4.0%
Total Depreciable	$ 93,476	$ 19,314	$ 74,162		-5.0%	$ -	$ (3,708)	$ (3,708)	-4.0%
Amortizable									
391.10 Office Furniture and Fixtures	$ 1,157,154	$ 666,067	$ 491,087						
391.90 Computers and Electronic Equipment	12,690,963	9,427,980	3,262,983						
394.00 Tools, Shop and Garage Equipment	132,128	111,800	20,328						
397.00 Communication Equipment	1,261,057	97,805	1,163,252						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 15,241,302	$ 10,303,652	$ 4,937,650						
Total General Plant	$ 15,334,778	$ 10,322,966	$ 5,011,812		-0.1%	$ -	$ (3,708)	$ (3,708)	
TOTAL TGS DIVISION	$ 15,334,778	$ 10,322,966	$ 5,011,812		-0.1%	$ -	$ (3,708)	$ (3,708)	

TEXAS GAS SERVICE - TGS Division
Current and Proposed Parameters
Vintage Group Procedure

Statement F

Account Description	Current Parameters						Proposed Parameters (at December 31, 2018)					
	P-Life/ AYFR	Curve Shape	Avg. Life	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	40.00	R1.5	40.01	37.96	-3.9	0.5	40.00	R1.5	40.10	34.88	-4.0	-5.0
Total Depreciable									40.10	34.88	-4.0	-5.0
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ					15.00	SQ	15.00	5.66		
391.90 Computers and Electronic Equipment	7.00	SQ					7.00	SQ	7.00	2.11		
394.00 Tools, Shop and Garage Equipment	15.00	SQ					15.00	SQ	15.00	9.10		
397.00 Communication Equipment	15.00	SQ					15.00	SQ	15.00	4.87		
398.00 Miscellaneous Equipment	15.00	SQ										
Total Amortizable									8.55	2.70		
Total General Plant									8.65	2.80		-0.1
TOTAL TGS DIVISION									8.65	2.80		-0.1

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the TGS depreciation study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for 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 3. 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
Central Texas Jurisdiction
Distribution Plant
Account: 376.00 Mains

Dispersion: 65 - R1.5
Procedure: Vintage Group

Generation Arrangement

Vintage	Age	December 31, 2018 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
2018	0.5	24,906,336	65.00	64.59	0.9937	1.0000	24,748,255	383,171
2017	1.5	8,679,695	65.00	63.77	0.9810	1.0000	8,514,537	133,527
2016	2.5	15,862,267	65.01	62.95	0.9683	1.0000	15,359,532	244,002
2015	3.5	23,845,715	65.02	62.13	0.9557	1.0000	22,788,185	366,762
2014	4.5	10,709,603	65.03	61.32	0.9430	1.0000	10,099,156	164,690
2013	5.5	28,117,239	65.04	60.51	0.9304	1.0000	26,159,693	432,285
2012	6.5	14,825,644	65.06	59.71	0.9178	1.0000	13,606,629	227,877
2011	7.5	7,940,349	65.07	58.91	0.9054	1.0000	7,189,027	122,033
2010	8.5	3,882,751	65.07	58.11	0.8930	1.0000	3,467,404	59,667
2009	9.5	2,863,956	64.96	57.32	0.8824	1.0000	2,527,133	44,088
2008	10.5	10,542,056	65.10	56.53	0.8684	1.0000	9,154,739	161,943
2007	11.5	4,071,884	65.19	55.74	0.8551	1.0000	3,481,694	62,458
2006	12.5	9,496,581	65.11	54.96	0.8442	1.0000	8,016,758	145,860
2005	13.5	3,458,474	65.19	54.18	0.8311	1.0000	2,874,438	53,050
2004	14.5	5,921,294	65.18	53.41	0.8193	1.0000	4,851,524	90,838
2003	15.5	9,288,330	65.32	52.64	0.8058	1.0000	7,484,843	142,199
2002	16.5	202,000	64.80	51.87	0.8004	1.0000	161,681	3,117
2001	17.5	1,656,105	65.08	51.10	0.7853	1.0000	1,300,548	25,449
2000	18.5	4,880,037	65.29	50.34	0.7711	1.0000	3,762,965	74,745
1999	19.5	5,486,420	65.20	49.59	0.7606	1.0000	4,172,775	84,150
1998	20.5	631,659	64.01	48.83	0.7629	1.0000	481,899	9,868
1997	21.5	2,628,812	64.61	48.08	0.7443	1.0000	1,956,554	40,690
1996	22.5	328,713	64.59	47.34	0.7329	1.0000	240,924	5,089
1995	23.5	164,596	64.93	46.60	0.7177	1.0000	118,133	2,535
1994	24.5	951,552	65.82	45.86	0.6968	1.0000	663,015	14,457
1993	25.5	788,095	64.47	45.13	0.7000	1.0000	551,631	12,224
1992	26.5	875,898	61.77	44.40	0.7188	1.0000	629,615	14,181
1991	27.5	6,020,283	65.30	43.68	0.6689	1.0000	4,026,889	92,199
1990	28.5	1,883,465	63.81	42.96	0.6731	1.0000	1,267,847	29,515
1989	29.5	1,422,944	63.57	42.24	0.6644	1.0000	945,466	22,382
1988	30.5	2,542,394	65.88	41.53	0.6304	1.0000	1,602,852	38,594
1987	31.5	3,562,497	65.83	40.83	0.6202	1.0000	2,209,448	54,118
1986	32.5	4,756,342	65.46	40.13	0.6130	1.0000	2,915,706	72,664
1985	33.5	5,579,163	67.08	39.43	0.5878	1.0000	3,279,601	83,172
1984	34.5	5,066,311	67.13	38.74	0.5772	1.0000	2,924,041	75,475
1983	35.5	1,974,924	67.14	38.06	0.5668	1.0000	1,119,472	29,415
1982	36.5	3,577,337	67.18	37.38	0.5564	1.0000	1,990,398	53,248

TEXAS GAS SERVICE COMPANY
Central Texas Jurisdiction
Distribution Plant
Account: 376.00 Mains
Dispersion: 65 - R1.5
Procedure: Vintage Group

Generation Arrangement

Vintage	Age (December 31, 2018)	Surviving Plant (December 31, 2018)	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
1981	37.5	3,768,272	67.72	36.71	0.5421	1.0000	2,042,642	55,647
1980	38.5	3,146,512	67.90	36.04	0.5308	1.0000	1,670,091	46,339
1979	39.5	2,838,839	67.98	35.38	0.5205	1.0000	1,477,546	41,762
1978	40.5	2,031,308	68.31	34.73	0.5083	1.0000	1,032,584	29,736
1977	41.5	881,481	68.34	34.08	0.4986	1.0000	439,520	12,898
1976	42.5	709,077	68.47	33.44	0.4883	1.0000	346,252	10,356
1975	43.5	702,067	68.82	32.80	0.4766	1.0000	334,630	10,202
1974	44.5	1,556,067	68.09	32.17	0.4725	1.0000	735,208	22,853
1973	45.5	1,412,574	69.41	31.55	0.4545	1.0000	642,075	20,352
1972	46.5	1,140,712	69.48	30.93	0.4452	1.0000	507,847	16,417
1971	47.5	990,861	69.51	30.33	0.4363	1.0000	432,276	14,255
1970	48.5	682,825	70.03	29.72	0.4245	1.0000	289,830	9,751
1969	49.5	755,043	70.46	29.13	0.4134	1.0000	312,150	10,716
1968	50.5	829,764	70.74	28.54	0.4035	1.0000	334,808	11,730
1967	51.5	317,637	71.04	27.96	0.3936	1.0000	125,029	4,471
1966	52.5	367,146	70.86	27.39	0.3866	1.0000	141,925	5,181
1965	53.5	471,334	71.57	26.83	0.3749	1.0000	176,685	6,586
1964	54.5	460,892	71.52	26.27	0.3673	1.0000	169,282	6,444
1963	55.5	493,737	72.17	25.72	0.3564	1.0000	175,954	6,841
1962	56.5	409,418	72.55	25.18	0.3471	1.0000	142,096	5,643
1961	57.5	458,156	72.96	24.65	0.3378	1.0000	154,775	6,280
1960	58.5	393,747	73.16	24.12	0.3297	1.0000	129,818	5,382
1959	59.5	542,330	73.80	23.60	0.3198	1.0000	173,449	7,349
1958	60.5	256,337	74.21	23.09	0.3112	1.0000	79,770	3,454
1957	61.5	178,411	74.17	22.59	0.3046	1.0000	54,340	2,405
1956	62.5	261,413	74.24	22.10	0.2977	1.0000	77,812	3,521
1955	63.5	284,778	74.52	21.61	0.2900	1.0000	82,584	3,821
1954	64.5	114,326	74.30	21.13	0.2844	1.0000	32,520	1,539
1953	65.5	140,096	72.42	20.66	0.2853	1.0000	39,974	1,934
1952	66.5	89,070	70.32	20.20	0.2873	1.0000	25,592	1,267
1951	67.5	124,407	73.66	19.75	0.2681	1.0000	33,355	1,689
1950	68.5	61,785	72.17	19.30	0.2675	1.0000	16,527	856
1949	69.5	158,600	76.08	18.87	0.2480	1.0000	39,329	2,085
1948	70.5	92,649	73.35	18.44	0.2514	1.0000	23,289	1,263
1947	71.5	28,803	64.30	18.02	0.2802	1.0000	8,070	448
1946	72.5	50,535	74.58	17.60	0.2360	1.0000	11,927	678
1945	73.5	21,176	74.68	17.20	0.2303	1.0000	4,876	284

TEXAS GAS SERVICE COMPANY
Central Texas Jurisdiction

Distribution Plant
Account: 376.00 Mains

Dispersion: 65 - R1.5
Procedure: Vintage Group

Generation Arrangement

Vintage	Age	December 31, 2018 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
1944	74.5	1,150	70.87	16.80	0.2370	1.0000	273	16
1943	75.5	792	68.25	16.41	0.2404	1.0000	190	12
1942	76.5	399,841	76.56	16.02	0.2093	1.0000	83,677	5,222
Total	14.7	$267,015,686	65.62	53.88	0.8211	1.0000	$219,245,582	$4,069,421

TEXAS GAS SERVICE COMPANY
Central Texas Jurisdiction
Distribution Plant
Account: 376.00 Mains

Age Distribution

Vintage	Age as of 12/31/2018	Derived Additions	1999 Opening Balance	Experience to 12/31/2018 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2018	0.5	24,906,336		24,906,336	1.0000	0.5000
2017	1.5	8,679,695		8,679,695	1.0000	1.5000
2016	2.5	15,865,600		15,862,267	0.9998	2.4999
2015	3.5	23,850,048		23,845,715	0.9998	3.4995
2014	4.5	10,709,603		10,709,603	1.0000	4.5000
2013	5.5	28,117,239		28,117,239	1.0000	5.5000
2012	6.5	14,828,796		14,825,644	0.9998	6.4989
2011	7.5	7,986,961		7,940,349	0.9942	7.4857
2010	8.5	3,899,354		3,882,751	0.9957	8.4682
2009	9.5	2,945,373		2,863,956	0.9724	9.3261
2008	10.5	10,644,515		10,542,056	0.9904	10.4325
2007	11.5	4,074,972		4,071,884	0.9992	11.4940
2006	12.5	9,652,065		9,496,581	0.9839	12.3691
2005	13.5	3,510,930		3,458,474	0.9851	13.4117
2004	14.5	6,019,878		5,921,294	0.9836	14.3578
2003	15.5	9,338,614		9,288,330	0.9946	15.4419
2002	16.5	213,872		202,000	0.9445	15.8719
2001	17.5	1,715,776		1,656,105	0.9652	17.0855
2000	18.5	5,038,393		4,880,037	0.9686	18.2356
1999	19.5	5,704,635		5,486,420	0.9617	19.0763
1998	20.5		732,522	631,659	0.8623	18.8171
1997	21.5		3,050,226	2,628,812	0.8618	20.3359
1996	22.5		372,624	328,713	0.8822	21.2375
1995	23.5		195,582	164,596	0.8416	22.4874
1994	24.5		997,892	951,552	0.9536	24.2890
1993	25.5		908,843	788,095	0.8671	23.8455
1992	26.5		1,668,800	875,898	0.5249	22.0370
1991	27.5		7,349,593	6,020,283	0.8191	26.4578
1990	28.5		2,217,794	1,883,465	0.8493	25.8619
1989	29.5		1,721,150	1,422,944	0.8267	26.5024
1988	30.5		2,667,640	2,542,394	0.9530	29.6783
1987	31.5		3,772,281	3,562,497	0.9444	30.4995
1986	32.5		5,200,809	4,756,342	0.9145	30.9900
1985	33.5		5,597,662	5,579,163	0.9967	33.4689
1984	34.5		5,103,576	5,066,311	0.9927	34.3637
1983	35.5		2,041,720	1,974,924	0.9673	35.2210
1982	36.5		3,752,876	3,577,337	0.9532	36.0981
1981	37.5		3,785,515	3,768,272	0.9954	37.4615

TEXAS GAS SERVICE COMPANY
Central Texas Jurisdiction
Distribution Plant
Account: 376.00 Mains

Age Distribution

Vintage	Age as of 12/31/2018	Derived Additions	1999 Opening Balance	Experience to 12/31/2018 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1980	38.5		3,154,116	3,146,512	0.9976	38.4662
1979	39.5		2,885,565	2,838,839	0.9838	39.3533
1978	40.5		2,031,987	2,031,308	0.9997	40.4942
1977	41.5		890,141	881,481	0.9903	41.3223
1976	42.5		719,181	709,077	0.9859	42.2388
1975	43.5		707,304	702,067	0.9926	43.3632
1974	44.5		1,653,504	1,556,067	0.9411	43.4099
1973	45.5		1,413,659	1,412,574	0.9992	45.4900
1972	46.5		1,152,754	1,140,712	0.9896	46.3188
1971	47.5		1,030,325	990,861	0.9617	47.0912
1970	48.5		692,237	682,825	0.9864	48.3430
1969	49.5		755,043	755,043	1.0000	49.5000
1968	50.5		830,608	829,764	0.9990	50.4929
1967	51.5		317,637	317,637	1.0000	51.5000
1966	52.5		385,352	367,146	0.9528	52.0112
1965	53.5		475,839	471,334	0.9905	53.3996
1964	54.5		504,615	460,892	0.9134	54.0287
1963	55.5		511,742	493,737	0.9648	55.3403
1962	56.5		421,298	409,418	0.9718	56.3631
1961	57.5		468,630	458,156	0.9776	57.4072
1960	58.5		421,258	393,747	0.9347	58.2328
1959	59.5		543,777	542,330	0.9973	59.4873
1958	60.5		256,412	256,337	0.9997	60.4949
1957	61.5		188,377	178,411	0.9471	61.0474
1956	62.5		289,339	261,413	0.9035	61.6859
1955	63.5		378,655	284,778	0.7521	62.5353
1954	64.5		156,268	114,326	0.7316	62.8582
1953	65.5		259,922	140,096	0.5390	61.5166
1952	66.5		157,814	89,070	0.5644	59.9307
1951	67.5		258,042	124,407	0.4821	63.7848
1950	68.5		201,714	61,785	0.3063	62.7861
1949	69.5		203,941	158,600	0.7777	67.1787
1948	70.5		161,177	92,649	0.5748	64.9083
1947	71.5		217,938	28,803	0.1322	56.3118
1946	72.5		89,140	50,535	0.5669	67.0298
1945	73.5		39,270	21,176	0.5392	67.5516
1944	74.5		17,053	1,150	0.0674	64.1417
1943	75.5		2,727	792	0.2904	61.9203

TEXAS GAS SERVICE COMPANY
Central Texas Jurisdiction
Distribution Plant
Account: 376.00 Mains

Age Distribution

Vintage	Age as of 12/31/2018	Derived Additions	1999 Opening Balance	Experience to 12/31/2018 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1942	76.5		950,296	399,841	0.4208	70.6095
1935	83.5		(1,905)		0.0000	64.0000
1901	117.5		1,801		0.0000	100.8783
1900	118.5		(2)		0.0000	99.0000
Total	14.7	$197,702,655	$76,931,658	$267,015,686	0.9723	

TEXAS GAS SERVICE COMPANY

Distribution Plant

Account: 376.00 Mains

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1999	188,939,897	12,698,452	773,997		200,864,352
2000	200,864,352	13,602,261	751,804		213,714,808
2001	213,714,808	5,989,125	6,684,246		213,019,687
2002	213,019,687	2,238,290	144,335		215,113,643
2003	215,113,643	12,476,563	8,627		227,581,579
2004	227,581,579	22,251,612	1,913,538		247,919,652
2005	247,919,652	18,263,351	633,389	28,805	265,578,420
2006	265,578,420	16,870,246	408,971		282,039,694
2007	282,039,694	19,324,351	716,565	(429,231)	300,218,248
2008	300,218,248	25,445,678	1,196,624		324,467,302
2009	324,467,302	12,612,921	2,354,484	1,164,586	335,890,326
2010	335,890,326	20,568,297	1,502,064		354,956,559
2011	354,956,559	21,589,845	1,434,276	115,077	375,227,206
2012	375,227,206	34,961,269	1,438,530	(56,464)	408,693,481
2013	408,693,481	43,356,995	2,088,090	(2,928,535)	447,033,851
2014	447,033,851	37,469,641	1,491,778	(124,841)	482,886,873
2015	482,886,873	44,466,817	3,413,823	138,909	524,078,776
2016	524,078,776	34,935,077	1,011,727	(47,055,152)	510,946,974
2017	510,946,974	33,156,096	1,060,845	(7,637,402)	535,404,823
2018	535,404,823	43,126,892	219,438	(5,483,554)	572,828,724

TEXAS GAS SERVICE COMPANY

Distribution Plant

Account: 376.00 Mains

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1999	193,671,033	12,787,615	773,997		205,684,651
2000	205,684,651	11,837,721	751,804		216,770,568
2001	216,770,568	6,782,477	6,684,246		216,868,799
2002	216,868,799	2,971,998	144,335		219,696,462
2003	219,696,462	18,376,077	8,627		238,063,912
2004	238,063,912	18,019,091	1,226,060	(687,479)	254,169,465
2005	254,169,465	12,618,686	633,389	28,805	266,183,567
2006	266,183,567	19,497,161	408,971		285,271,757
2007	285,271,757	15,869,992	716,565	(429,231)	299,995,953
2008	299,995,953	27,133,164	1,196,624		325,932,493
2009	325,932,493	12,005,322	2,354,484	1,164,586	336,747,918
2010	336,747,918	19,741,822	1,502,064		354,987,675
2011	354,987,675	22,842,465	1,434,276	115,077	376,510,942
2012	376,510,942	37,689,430	1,438,530	(56,464)	412,705,377
2013	412,705,377	47,990,033	2,088,090	(2,928,535)	455,678,786
2014	455,678,786	36,467,104	1,491,778	(124,841)	490,529,270
2015	490,529,270	45,873,230	3,413,823	138,909	533,127,587
2016	533,127,587	35,100,397	1,011,727	(47,055,152)	520,161,105
2017	520,161,105	27,042,135	1,060,845	(7,637,402)	538,504,993
2018	538,504,993	40,026,722	219,438	(5,483,554)	572,828,724

TEXAS GAS SERVICE COMPANY

Distribution Plant

Account: 376.00 Mains

T-Cut: None

Placement Band: 1900-2018

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	2.1	72.6	L0	10.19	113.8	O3 *	16.93	58.9	R1 *	8.94
2000-2004	14.5	99.5	O3	6.67	138.3	SC *	14.50	64.8	R1 *	11.90
2001-2005	13.5	104.2	O2	8.45	140.0	SC *	16.06	64.6	R1.5 *	13.19
2002-2006	27.9	151.6	R1	14.29	88.9	R2.5	5.67	79.8	R3	13.70
2003-2007	11.1	137.7	R0.5	24.31	81.9	R2.5	6.03	75.0	R3	6.71
2004-2008	0.1	126.4	SC	29.36	78.0	R2	10.84	71.6	R3	4.25
2005-2009	0.0	107.9	S-.5	25.51	74.2	R2	9.78	68.5	R3	3.46
2006-2010	0.8	110.0	SC	25.35	77.6	R1.5	12.73	69.2	R3	3.84
2007-2011	0.3	105.0	SC	24.86	78.5	R1.5	14.98	68.6	R2.5	4.59
2008-2012	0.0	97.8	L0	22.63	76.3	R1	13.51	67.4	R2.5	2.52
2009-2013	0.0	80.9	L0.5	17.30	67.4	R1.5	8.65	63.4	R2.5 *	2.13
2010-2014	0.0	83.6	L1	17.61	70.8	S1	9.65	65.2	R2.5 *	2.52
2011-2015	0.0	68.7	L1.5 *	10.05	62.9	S1	5.56	60.6	R2 *	3.75
2012-2016	0.0	70.2	L1.5 *	13.02	64.1	S1	7.61	61.4	R2 *	4.16
2013-2017	0.0	71.6	L1.5 *	13.73	65.3	S1	8.26	62.4	R2 *	4.79
2014-2018	0.0	82.4	L1.5 *	18.96	74.2	S1	13.68	69.5	R2 *	9.50

TEXAS GAS SERVICE COMPANY

Distribution Plant

Account: 376.00 Mains

T-Cut: None

Placement Band: 1900-2018

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
1999-2018	0.0	84.7	L0.5	16.84	72.7	S0.5	9.53	65.9	R2.5 *	1.83
2001-2018	0.0	86.1	L0.5	16.97	74.5	S0.5	10.51	66.3	R2.5 *	2.60
2003-2018	0.0	89.0	L1	18.14	73.5	S1	8.31	68.0	R2.5 *	2.64
2005-2018	0.0	86.3	L1	17.08	72.5	S1	7.96	67.4	R2.5 *	2.55
2007-2018	0.0	83.8	L1	16.28	71.7	S1	8.11	66.6	R2.5 *	2.49
2009-2018	0.0	81.6	L1	16.56	71.2	S1	9.54	66.0	R2.5 *	3.85
2011-2018	0.0	80.4	L1.5 *	16.68	70.6	S1	9.66	66.3	R2.5 *	4.89
2013-2018	0.0	77.7	L1.5 *	16.80	69.3	S1.5	10.31	65.6	R2.5 *	6.05
2015-2018	0.0	80.4	L1.5 *	18.11	72.6	S1	12.59	69.3	R2 *	9.67
2017-2018	0.0	111.8	L1.5 *	33.04	85.6	S2	20.53	77.4	R4 *	13.00

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TEXAS GAS SERVICE COMPANY
Distribution Plant
Account: 376.00 Mains

T-Cut: None
Placement Band: 1900-2018
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	66.1	L1.5 *	14.13	57.4	R2.5	5.91	57.5	R3	6.39
1999-2002	0.8	61.3	L0	8.09	98.3	O4 *	14.37	53.6	R1 *	8.30
1999-2004	1.3	81.2	O2	12.36	107.4	O3 *	15.63	60.8	R1.5 *	7.82
1999-2006	3.5	92.2	L0	14.25	83.0	L0.5	12.02	64.4	R2	7.14
1999-2008	0.5	96.9	L0	19.05	78.0	S0	12.68	65.6	R2	4.64
1999-2010	0.6	96.5	L0	19.57	77.8	S0	12.99	65.6	R2	3.69
1999-2012	0.0	95.9	L0	20.17	76.9	R1	12.54	66.2	R2.5	2.60
1999-2014	0.0	88.2	L0.5	18.39	72.5	R1	10.12	64.9	R2.5 *	2.21
1999-2016	0.0	81.2	L0.5	15.38	70.3	S0.5	8.59	64.1	R2 *	1.59
1999-2018	0.0	84.7	L0.5	16.84	72.7	S0.5	9.53	65.9	R2.5 *	1.83

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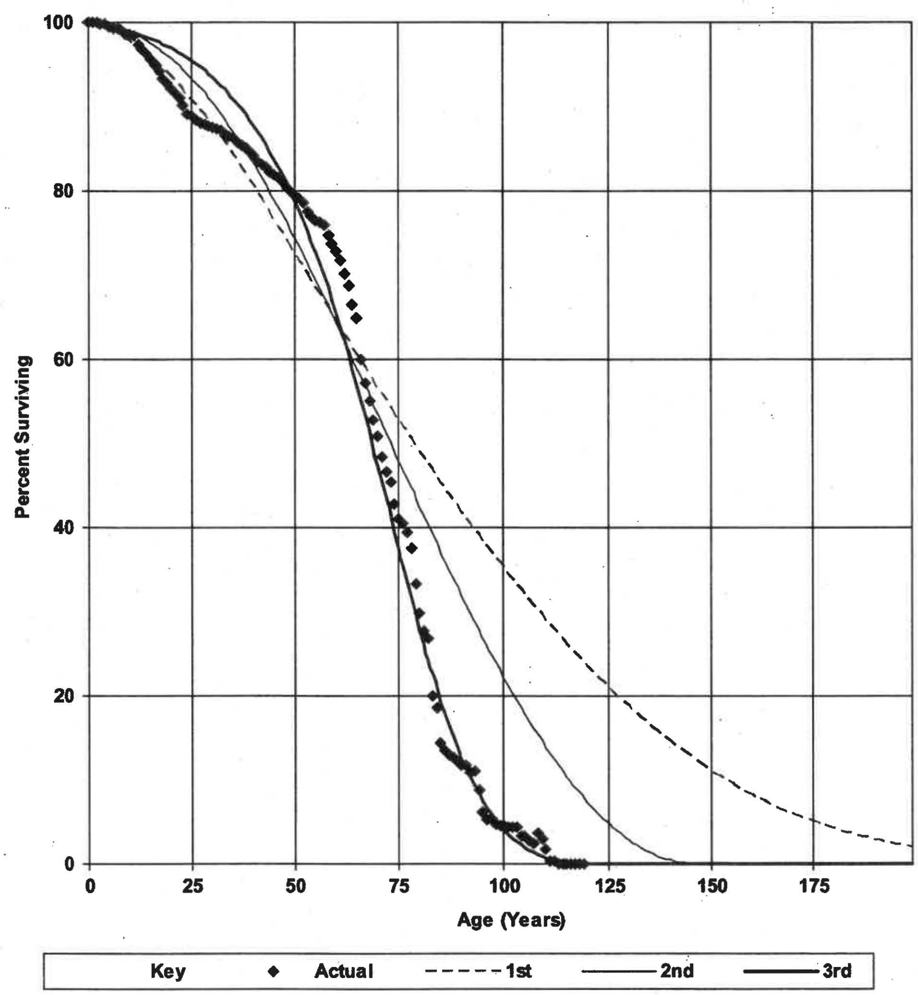
TEXAS GAS SERVICE COMPANY
Distribution Plant
Account: 376.00 Mains

T-Cut: None
Placement Band: 1900-2018 Observation Band: 1999-2018
Hazard Function: Proportion Retired
Weighting: Exposures

Survivorship Functions

1st: 84.7-L0.5 2nd: 72.7-S0.5 3rd: 65.9-R2.5

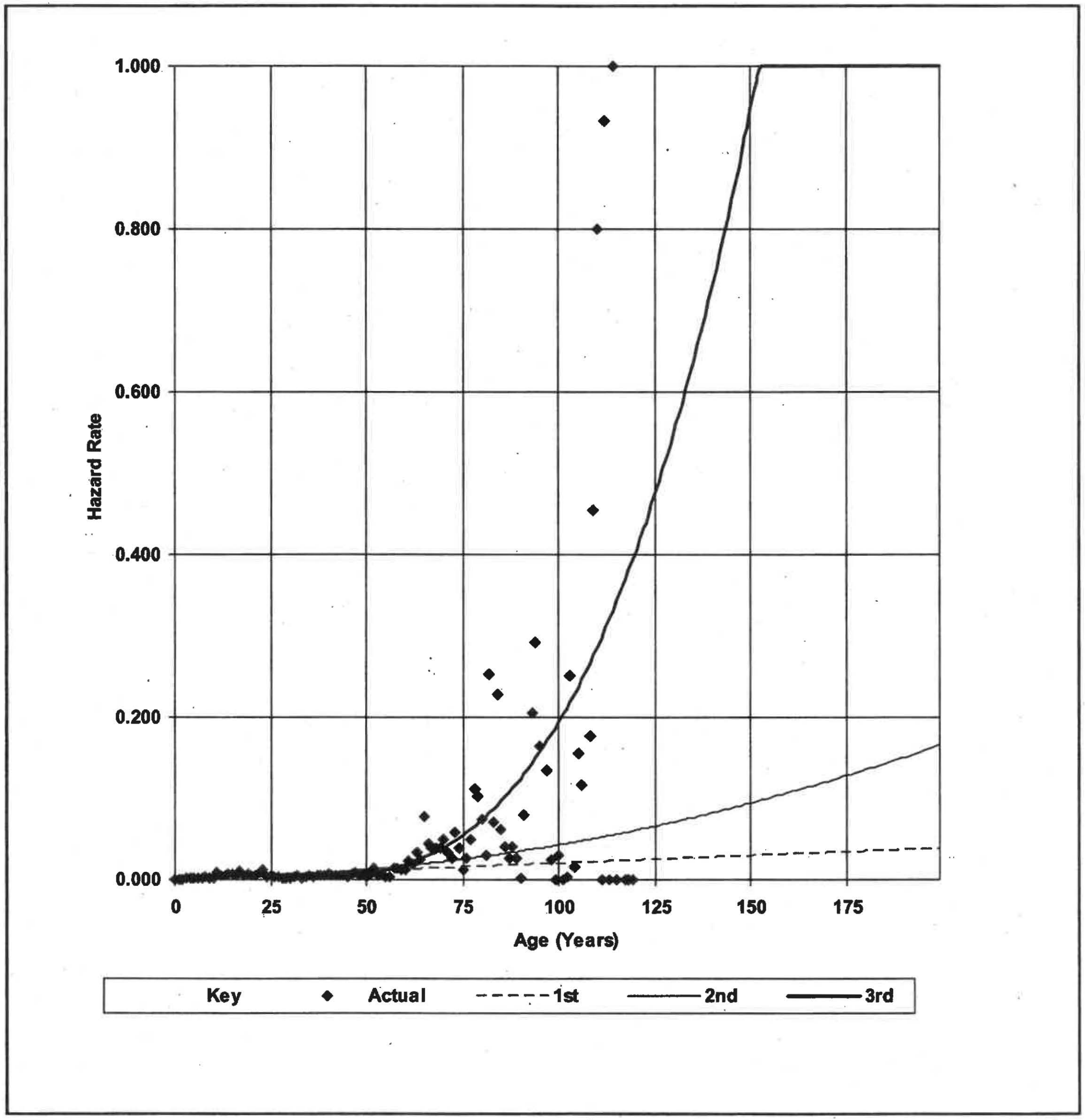


TEXAS GAS SERVICE COMPANY
Distribution Plant
Account: 376.00 Mains

T-Cut: None
Placement Band: 1900-2018 Observation Band: 1999-2018
Hazard Function: Proportion Retired
Weighting: Exposures

Polynomial Hazard Functions

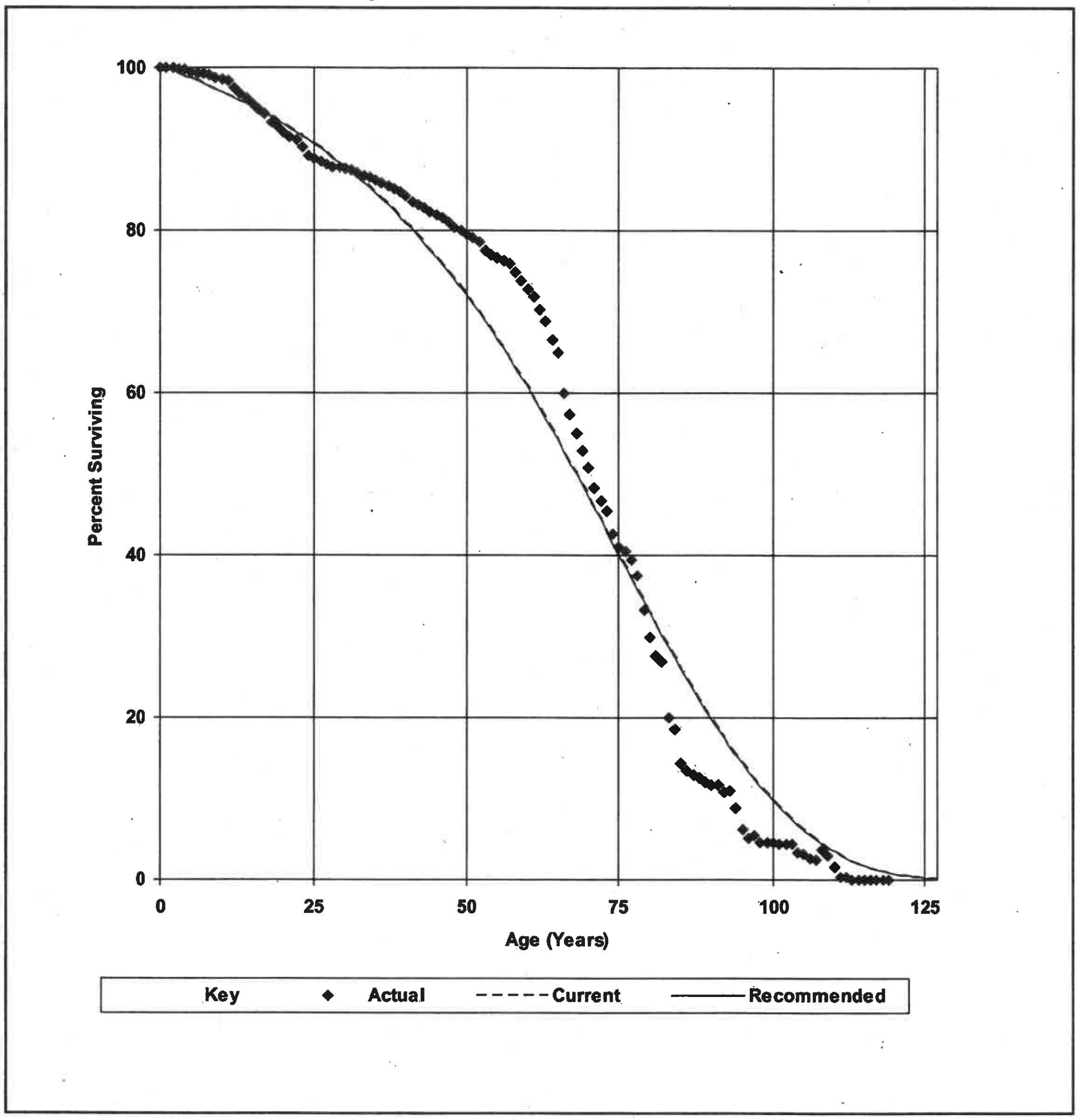
1st: 84.7-L0.5 2nd: 72.7-S0.5 3rd: 65.9-R2.5



TEXAS GAS SERVICE COMPANY
Distribution Plant
Account: 376.00 Mains

T-Cut: None
Placement Band: 1900-2018
Observation Band: 1999-2018

Current and Recommended Projection Life Curves Current: 65.0-R1.5 Recommended: 65.0-R1.5



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	738,255	336.4	358.5	(738,255)	-336.4	-358.5
Total	29,247,153	177,005	0.6		48,840,189	167.0		(48,663,183)	-166.4	

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	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	1,226,060		0.0	0.0	183,511	15.0	2.5	(183,511)	-15.0	-2.5
2005	633,389	(867)	-0.1	0.0	592,533	93.5	9.1	(593,400)	-93.7	-9.2
2006	408,971		0.0	0.0	335,894	82.1	46.2	(335,894)	-82.1	-46.2
2007	716,565		0.0	0.0	657,681	91.8	59.2	(657,681)	-91.8	-59.2
2008	1,196,624		0.0	0.0	1,182,690	98.8	70.6	(1,182,690)	-98.8	-70.6
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	738,255	336.4	358.5	(738,255)	-336.4	-358.5
Total	28,559,674	9,891	0.0		48,840,189	171.0		(48,830,298)	-171.0	

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 this 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 25th day of November, 2019.

Lynnette A. Jay
Notary Public, State of Florida
My Comm. Expires March 7, 2021
Commission No. GG 80655

Lynnette A. Jay
Notary Public in and for the State of Florida

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

BRUCE H. FAIRCHILD

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

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. My purpose is to recommend an overall rate of return to apply to Texas Gas Service Company's ("TGS") invested capital for its proposed Central-Gulf Service Area ("CGSA").

Q. WHAT IS THE ROLE OF RATE OF RETURN IN SETTING A UTILITY'S RATES?

A. 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 DEVELOPED 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 financial crisis and Great Recession. With this background, I next 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 my recommended ROE for TGS is selected and evaluated for reasonableness. Finally, these components are combined to calculate my recommended overall rate of return for the proposed CGSA.

C. Summary of Conclusions

Q. WHAT IS YOUR RATE OF RETURN RECOMMENDATION?

A. As developed on Schedule BHF-1, I recommend an overall rate of return for TGS on the invested capital in its proposed CGSA of 7.93%. This rate of return is based on capital structure ratios of 37.88% debt and 62.12% equity, a cost of debt of 4.53%, and an ROE of 10.0%.

Q. WHAT ARE YOUR RECOMMENDED CAPITAL STRUCTURE RATIOS FOR TGS?

A. My recommended capital structure ratios of 37.88% debt and 62.12% equity are those of ONE Gas, Inc. ("ONE Gas"), of which TGS is a division, as of the end of the test year, June 30, 2019. These ratios are consistent with the capital structure ONE Gas has maintained since it was spun off from ONEOK, Inc. ("ONEOK") into a stand-alone company on January 31, 2014. They reflect ONE Gas' need to establish a credit profile supporting an industry standard, single-A bond rating that enables it to attract new capital on reasonable terms and maintain its financial integrity. Besides being TGS's actual capital structure and conforming to the normal practice of the Railroad Commission of Texas ("Commission"), ONE Gas' test year-end capital structure ratios are generally consistent with and fall within the range of those historically maintained by other local natural gas distribution companies ("LDCs") and approved in LDC rate cases before the Commission.

Q. WHAT IS YOUR RECOMMENDED COST OF DEBT FOR TGS?

A. My recommended 4.53% cost of debt is the average cost of ONE Gas' approximately $1.285 billion of long-term debt at the June 30, 2019 test year-end.

Q. WHAT IS YOUR RECOMMENDED ROE FOR TGS?

A. Based on applications of the DCF, CAPM, risk premium, and comparable earnings methods to a proxy group of publicly traded LDCs, I conclude that investors currently require a ROE from a publicly traded LDC in the range of 9.1% to 10.1%. Despite recent increases in stock prices and declines in interest rates, the cost of all capital, including common equity, is projected to be considerably higher over the next few years. This implies that the ROE for TGS should be selected from the top of the cost of equity range, which is slightly offset by ONE Gas' capital structure ratios that indicate modestly lower financial risk relative to the LDC proxy group. Therefore, I recommend an ROE for TGS just below the top of my 9.1% to 10.1% cost of equity range, or 10.0%. The reasonableness of my recommended ROE is evidenced by the fact that it falls within the 9.5% to 10.1% range the Commission has granted LDCs in Texas the last approximately five years.

II. FUNDAMENTAL ANALYSIS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of TGS and ONE Gas. It also examines the natural gas distribution industry along with current conditions in the capital markets and the 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 640,000 sales and transport customers in 100 communities throughout Texas. In addition to its proposed CGSA, which includes the major cities of Austin, Port Arthur and Galveston, TGS also serves the Rio Grande Valley and the city of El Paso. In total, TGS serves approximately 14% of the natural gas customers in Texas. At June 30, 2019, TGS had total assets of approximately $1.4 billion, with operating revenues for the previous twelve months being approximately $391 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 approximately 2.2 million customers. ONE Gas was created when ONEOK spun off its natural gas distribution operations into a separate entity on January 31, 2014. At June 30, 2019, ONE Gas had total assets of approximately $5.4 billion, with revenues during 2018 totaling more than $1.6 billion. ONE Gas' common stock is traded on the New York Stock Exchange and its debt is rated A by Standard & Poor's Financial Services LLC ("S&P") and A2 by Moody's Investors Service, Inc. ("Moody's").

B. Natural Gas Distribution Industry

Q. PLEASE DESCRIBE THE NATURAL GAS DISTRIBUTION INDUSTRY.

A. LDCs normally transport, deliver, and sell natural gas from receipt points on inter- and intrastate pipelines to households and businesses. They often have 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 improvements 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.

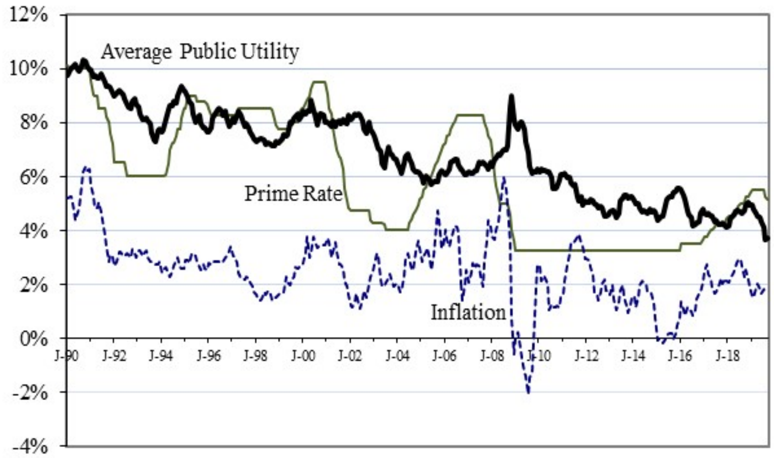
Finally, because most aspects of an LDC's operations (e.g., rates; operating terms and conditions of service; types of services offered; construction of new facilities; the integrity, safety, and security of facilities and operations; acquisition, extension, or abandonment of services or facilities; 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.

C. Capital Markets

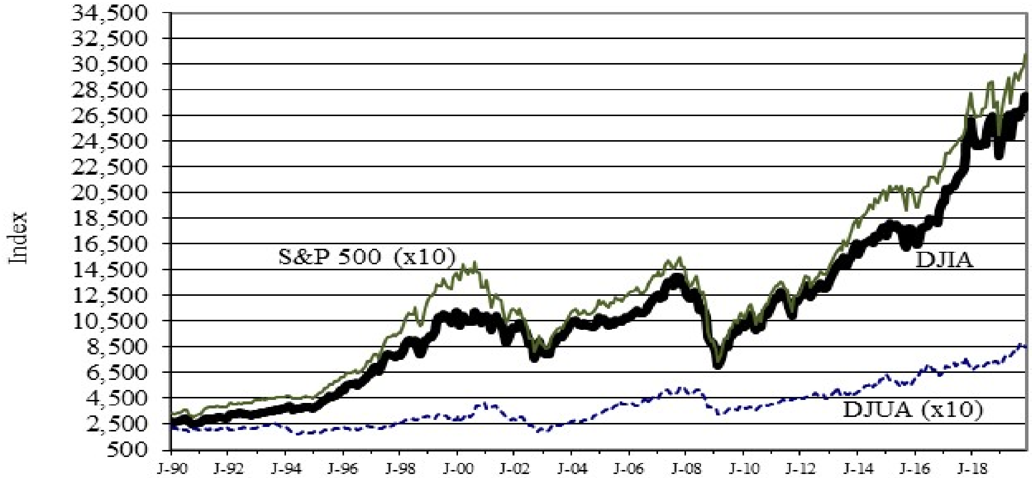
Q. WHAT HAS BEEN THE PATTERN OF INTEREST RATES OVER THE LAST TWO DECADES?

A. Average long-term public utility bond rates, the borrowing prime rate, and inflation as measured by the Consumer Price Index since 1990 are plotted in the graph below. After rising to approximately 10% in mid-1990, the average yield on long-term public utility bonds generally fell because of monetary and fiscal policies designed to keep the economy growing. This ended abruptly with the 2008 financial market meltdown and global recession. Investors became exceedingly risk averse, causing interest rates on corporate bonds to spike, while government policies pushed down short-term interest rates and depressed economic conditions and lower energy prices reduced inflation. Since that time, various actions by the Fed to stimulate the economy through easy-money policies resulted in short- and long-term interest rates reaching record low levels:



Q. HOW HAS THE MARKET FOR COMMON EQUITY CAPITAL PERFORMED OVER THIS SAME PERIOD?

A. Between 1990 and early 2000, stock prices pushed steadily higher as the longest bull market in United States 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 global recession hit in 2008. Stock prices tumbled by some 40%, and although they have fully recovered and reached all-time highs, the market remains volatile, with share values routinely changing in 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 1990 (the latter two indices were scaled for comparability):



Q. WHAT IS THE OUTLOOK FOR THE U.S. ECONOMY?

A. The U.S. economy has fully recovered from the Great Recession precipitated by the 2007-2009 financial crisis that led the Fed to implement extraordinary programs, which included reducing the federal funds rate to effectively zero and purchasing some $4.5 trillion in mortgage-backed and Treasury securities. In December 2015, the Fed began to return to more "normal" monetary policies by increasing the target federal funds rate unwinding its massive portfolio of securities. As foreign economies slowed and a trade war persisted, the U.S. economic outlook began to turn in early 2019, with an inverted yield curve portending a recession. The Fed responded by reducing the federal funds rate and discontinuing the unwinding of its $3.8 trillion securities portfolio.

The economic outlook is now more uncertain than ever, in large part due to continued global economic and trade uncertainty. That uncertainty, combined with overhanging recession fears, aggravate the normal uncertainties faced by the U.S.

economy and capital markets, which is evidenced by unusually greater stock and bond price volatility. Although stock prices have recently increased and interest rates fallen, these are largely regarded as temporary. For example, *The Value Line Investment Survey* ("*Value Line*") and the *Blue Chip Financial Forecasts* both project interest rates on 30-year Treasury bonds to increase from their current level of approximately 2.1% to 3.6% in the 2023 time-frame, which implies a higher cost of all capital, including common equity, over the next few years.

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 the proposed CGSA.

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. HOW DOES THE USE OF DIFFERENT AMOUNTS OF DEBT AND EQUITY IN A FIRM'S CAPITAL STRUCTURE AFFECT THE RATES OF RETURN REQUIRED BY INVESTORS?

A. A higher debt ratio, or lower common equity ratio, generally translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This, in turn, increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest for bearing this increased risk. From common shareholders' viewpoint, higher debt ratios mean that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any, that remains. Again, in accordance with the fundamental risk-return trade-off principle to be discussed in greater detail later, common shareholders require a correspondingly higher rate of return to compensate them for bearing the greater financial risk associated with a lower common equity ratio.

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, including those in its proposed CGSA.

Q. WHAT ARE THE SOURCES OF CAPITAL USED TO FINANCE ONE GAS?

A. ONE Gas' permanent financing at test year-end, June 30, 2019, is shown below (dollar amounts in 000s). Also calculated are ONE Gas' test year-end capital structure ratios, which were 37.88% debt and 62.12% equity:

Capital Component	Amount	% of Total
Long-term Debt	$ 1,285,811	37.88%
Common Equity	2,108,463	62.12
Total	**$ 3,153,466**	**100.00%**

Q. WHAT CONSIDERATIONS WENT INTO HOW ONE GAS WAS FINANCED WHEN IT WAS SPUN OFF FROM ONEOK?

A. The Registration Form 10 filed with the Securities and Exchange Commission in connection with the spin-off of ONE Gas from ONEOK 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 has since been increased to A, and A2 by Moody's. As shown on Schedule BHF-9, single-A is the average bond rating of the publicly traded LDCs included in *Value Line's* Natural Gas Utility industry that are predominantly involved in natural gas distribution and are not affected by an acquisition or divestiture. Also, ONE Gas' single-A ratings are an improvement over the triple-B bond ratings of ONEOK prior to the spin off. Of additional importance is that ONE Gas' capital structure and single-A bond ratings enabled it to issue its initial debt on favorable terms, which has been a direct benefit to customers.

Q. HAS ONE GAS MAINTAINED SIMILAR CAPITAL STRUCTURE RATIOS SINCE ITS INCEPTION?

A. Yes. Schedule BHF-2 displays the capital structure of ONE Gas at each year-end since it became a separate entity in 2014. As evidenced there, ONE Gas' capital structure ratios have generally remained in the approximately 40% debt and 60%

equity vicinity over this period, although its equity ratio has increased slightly as earnings have been retained and reinvested in the Company's distribution system. Most recently, ONE Gas increased its debt outstanding by $100 million when it refinanced $300 million that matured earlier in 2019.

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 2013 and 2017:

Capital Component	2017	2016	2015	2014	2013
Long-term Debt	41.6%	40.1%	42.0%	42.3%	42.4%
Preferred Stock	0.1%	1.1%	0.6%	1.0%	0.1%
Common Equity	58.3%	58.8%	57.3%	56.7%	57.5%
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 BHF-3 displays the capital structure ratios at each fiscal year-end between 2014 and 2018 for the eight LDCs other than ONE Gas in the proxy group identified later in my testimony. While ONE Gas' test year-end capital structure ratios of approximately 38% debt and 62% equity are below and above, respectively, the averages for this group over the last five years, they fall well within industry bounds. Moreover, it is noteworthy that the LDCs in the proxy group are longstanding companies that did not need to establish their creditworthiness to be able to attract new capital on reasonable terms and maintain their financial integrity as ONE Gas did when it was spun-off from ONEOK.

Q. HAS ANYTHING OCCURRED RECENTLY THAT ILLUSTRATES THE BENEFIT OF ONE GAS MAINTAINING DEBT AND EQUITY RATIOS AT THE LOWER AND UPPERS 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. 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. WHAT CAPITAL STRUCTURE RATIOS HAS THE COMMISSION APPROVED FOR LDCS IN TEXAS OVER THE LAST FIVE YEARS?

A. The table below lists the capital structure ratios approved by the Commission for the larger LDCs in Texas from 2015 through the present. As shown there, with but a few exceptions, the equity ratios included in the rates of return authorized by the Commission over the last five year have been above 60%:

Date	Docket	Utility	Debt	Equity
8/25/2015	10432	CP Entex – Houston	45.50%	54.50%
5/3/2016	10488	TGS – Gulf Coast	39.80%	60.20%
9/27/2016	10506	TGS – West Texas	39.90%	60.10%
11/15/2016	10526	TGS – Central Texas	39.50%	60.50%
5/23/2017	10567	CP Entex – Houston	44.85%	55.15%
12/5/2017	10640	Atmos – Dallas	41.49%	58.51%
3/20/2018	10656	TGS – RGV	38.71%	61.29%
5/22/2018	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%
2/5/20199	10766	TGS – BSSA	37.84%	62.16%
5/21/2019	10779	Atmos – Mid-Tex	39.82%	60.18%

Q. WHAT CAPITAL STRUCTURE RATIOS DO YOU RECOMMEND BE USED TO CALCULATE THE RATE OF RETURN FOR THE PROPOSED CGSA?

A. I recommend that the rate of return for the proposed CGSA be calculated using ONE Gas' June 30, 2019 test year-end capital structure ratios of 37.88% debt and 62.12% equity, which were designed to secure a credit rating similar to other LDCs when ONE Gas was spun-off from ONEOK and support its solid single-A rating. 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 over the last five years in rate cases for in TGS's Gulf Coast, West Texas, Central Texas, Rio Grande Valley, North Texas, and Borger-Skellytown service areas.

IV. <u>COST OF DEBT</u>

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 the capital structure used to calculate an overall rate of return for the proposed CGSA.

Q. PLEASE DESCRIBE THE DEBT ONE GAS ISSUED AT ITS INCEPTION.

A. In conjunction with its spin-off from ONEOK in January 2014, ONE Gas completed the private placement of three series of senior notes, consisting of $300 million maturing in 2019 and carrying an interest rate of 2.07%, $300 million due in 2024 with an interest rate of 3.61%, and $600 million maturing in 2044 at an interest rate of 4.658%. The favorable interest rates on the debt issued by ONE Gas reflected capital market conditions at the time of issue, its capital structure ratios, and the single-A bond rating ONE Gas had received from S&P and Moody's.

Q. WHAT HAS OCCURRED SINCE ONE GAS INITIALLY ISSUED DEBT?

A. In November 2018, ONE Gas issued $400 million of new, 30-year notes that mature in November 2048. The proceeds from the sale were used to retire the $300 million of senior notes that were scheduled to mature in early 2019 and fund other corporate purposes. The interest rate on the new 2048 notes is 4.50%.

Q. WHAT IS THE AVERAGE COST OF ONE GAS' DEBT?

A. As developed below, the weighted average cost of ONE Gas' outstanding debt at the June 30, 2019 is 4.53% (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
Debt Issuance Costs Expenses	(11,158)		439
Debt Retirement Costs	(6,893)		811
Total	**$ 1,281,948**		**$ 58,028**
Cost of Debt		**4.53%**	

Q. WHAT COST OF DEBT DO YOU RECOMMEND BE USED TO CALCULATE THE RATE OF RETURN FOR THE PROPOSED CGSA?

A. Consistent with using ONE Gas' actual capital structure ratios at June 30, 2019, I recommend that the rate of return for the proposed CGSA be calculated using ONE Gas' test year-end cost of debt of 4.53%. This cost of debt reflects ONE Gas' single-A bond rating, which is largely predicated on its actual capital structure ratios. It is also consistent with how the cost of debt was determined in the rates of return approved by the Commission in TGS's Gas Utilities Docket Nos. 10488, 10506, 10526, 10656, 10739 and 10766.

V. <u>RETURN ON EQUITY</u>

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 a proxy 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 proxy 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 proxy 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.

A. Cost of Equity Concept

Q. HOW IS A RATE OF RETURN ON COMMON EQUITY CUSTOMARILY DETERMINED?

A. Unlike debt capital, there is no contractually guaranteed return on common equity capital, because 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 September 2019 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.

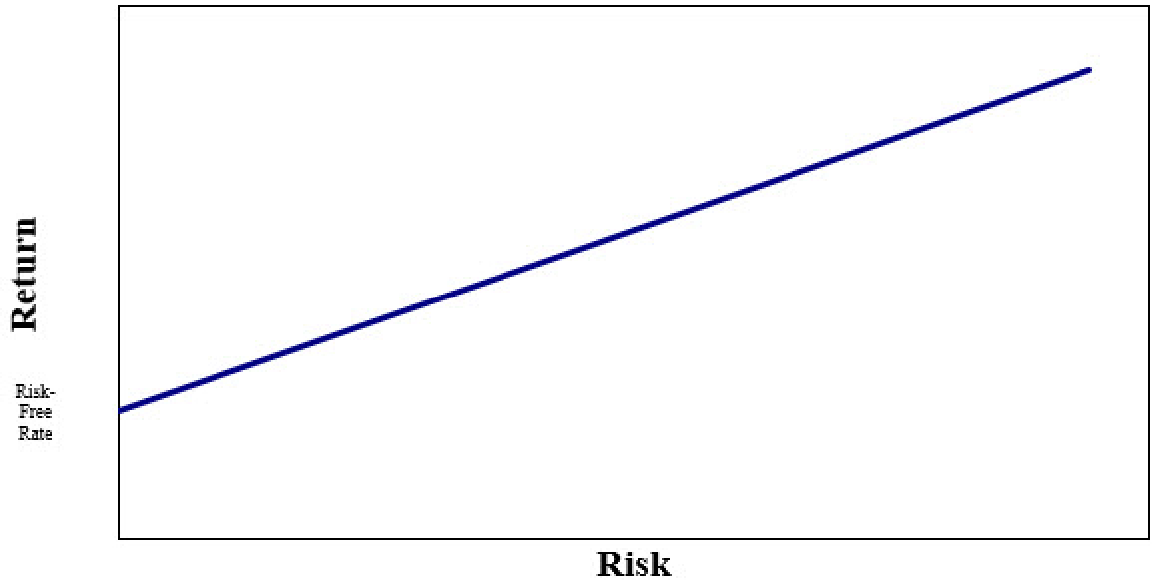
Bond and Rating	September 2019 Yield	Risk Premium Over 30-Year Treasury
U.S. Treasury		
30-Year	2.41%	--
Public Utility		
Aa	3.24%	0.83%
A	3.37%	0.96%
Baa	3.71%	1.30%

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 for TGS. 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 that 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 that 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;
K_e = 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 proxy group of publicly traded LDCs identified earlier, which includes ONE Gas. Specifically, I began with the ten companies included in *Value Line's* Natural Gas Utility industry and excluded those that are not predominantly engaged in natural gas distribution (*i.e.*, UGI Corp.). This resulted in a proxy 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.

Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL 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* October 11, 2019 edition, by the average daily closing price of each firm's stock during the month of September 2019. The expected dividends, representative price, and resulting dividend yield for each of the nine gas utilities are displayed on Schedule BHF-4. As also shown there, the average dividend yield for the industry group is 2.58%, with a median of 2.67%.

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*, Thomson Reuters' *Institutional Brokers Estimate System* ("*I/B/E/S*"), and *Zacks Investment Research* ("*Zacks*") are displayed on Schedule BHF-5, with the averages for the group being 8.2%, 5.4%, and 6.6%, respectively. To eliminate the impact of extreme values, the medians for the group are also shown, which range between 4.7% and 8.5%. Also shown on Schedule BHF-5 are the 10-year and 5-year historical earnings growth rates reported by *Value Line* for each of the nine gas utilities, which average 5.8% and 7.1%, respectively, and have medians of 6.8% and 7.5%, respectively.

Q. HOW ELSE ARE INVESTOR EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS FOR A FIRM OFTEN ESTIMATED FOR USE IN THE CONSTANT GROWTH DCF MODEL?

A. In DCF theory and practice, growth in book equity comes from the reinvestment of earnings within the business and the effects of external financing. Accordingly, conventional applications of the constant growth DCF model often examine the relationships between variables that determine the "sustainable" growth attributable to these two factors.

Q. HOW IS A FIRM'S SUSTAINABLE GROWTH ESTIMATED?

A. The sustainable growth rate is calculated by the formula:

$$g = br + sv$$

where "b" is the expected earnings retention ratio (one minus the dividend payout ratio), "r" is the expected rate of return earned on book equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion ratio. The "br" term represents the growth from reinvesting earnings within the firm while the "sv" term represents the growth from external financing. This external financing growth results because existing shareholders share in a portion of any excess received from selling new shares at a price above book value.

Q. WHAT GROWTH RATE DOES THE SUSTAINABLE GROWTH METHOD SUGGEST FOR THE GAS UTILITY GROUP?

A. The sustainable growth rate for each of the gas utilities in the industry group based on *Value Line's* projections for 2021-2023 is developed in Schedule BHF-6. As shown there, the sustainable growth method implies an average long-term growth rate for the gas utility group of 7.3%, and 6.5% based on the median.

Q. WHAT ARE OTHER PROJECTED AND HISTORICAL GROWTH RATES FOR THE INDUSTRY GROUP?

A. Schedule BHF-7 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 2.6% (projected growth in share price) to 13.2% (5-year historical growth in share price), with the corresponding medians ranging from 2.1% to 12.5%. Besides the fact that some of these growth rates, when combined with the group's 2.6% 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 BHF-5, BHF-6, and BHF-7 indicate a range for the LDC group of between approximately 6.0% and 8.0%, which compares with *Zacks* projected earnings growth rate for its gas distribution industry of 7.8%. Taken together, I conclude that investors expect long-term growth from the LDC group in the 6.5% to 7.5% range.

Q. WHAT CURRENT DCF COST OF EQUITY ESTIMATES DO THESE GROWTH RATE RANGES IMPLY FOR THE GAS UTILITY GROUP?

A. Summing the LDC group's dividend yield of approximately 2.6% with a 6.5% to 7.5% growth rate range indicates a current 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, and Duff & Phelps. Most recently, Duff & Phelps reports that the annual rate of return realized on the S&P 500 averaged 11.88% over the period 1926 through 2018 while the annual average income rate of return on 30-year Treasury bonds over this same period averaged 4.97%. Thus, the market risk premium based on historical average annual rates of return is 6.91%.

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 BHF-8, summing the 2.41% 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 9.31% produces a required rate of return from the market portfolio (R_m) of 11.71%.

Q. WHAT IS THE MARKET RISK PREMIUM BASED ON FORWARD-LOOKING REQUIRED RATES OF RETURN?

A. From the 11.71% 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 September 2019 of 2.12%. This produces a forward-looking market risk premium of 9.59%.

Q. WHAT IS THE NEXT STEP IN APPLYING THE CAPM?

A. Having calculated market risk premiums of 6.91% and 9.59% using historical rates of return and forward-looking rates of return, respectively, the next step in the CAPM method 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 0.66, calculated using firm betas obtained from *Value Line* and shown on Schedule BHF-9, which produces current industry risk premiums of 4.53% and 6.29%.

Q. WHAT ARE THE RESULTING THEORETICAL CAPM COST OF EQUITY ESTIMATES FOR THE LDC GROUP?

A. As developed in Schedule BHF-8, summing the industry risk premiums of 4.53% and 6.29% with a risk-free interest rate equal to the September 2019 30-year

Treasury bond yield of 2.12% produces current theoretical CAPM cost of equity estimates for the LDC industry group of 6.65% and 8.41%.

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, Duff & Phelps has developed size premiums 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. As shown on Schedule BHF-9, the average market capitalization of the LDC group is $5.4 billion. Based on Duff & Phelps most recent schedule of size premiums, which is reproduced in the lower portion of Schedule BHF-9, this means that the theoretical CAPM cost of equity estimates need to be increased by 0.82% to account for the LDC industry group's smaller size relative to the S&P 500. As shown on Schedule BHF-8, increasing the theoretical CAPM cost of equity estimates for the LDC group by this size premium results in current CAPM cost of equity estimates based on historical rates of return and forward-looking rates of return of 7.47% and 9.23%, respectively.

D. Risk Premium Method

Q. HOW ELSE DID YOU ESTIMATE THE COST OF EQUITY?

A. I also estimated the cost of equity using a risk premium method based on ROEs previously authorized for LDCs by state regulatory commissions. The risk premium method to estimate investors' required rate of return is an extension of the risk-return tradeoff observed with bonds to common stocks. The cost of equity is estimated by determining the additional return investors require to forego the relative safety of a bond and bear the greater risks associated with common stock, and then adding this equity risk premium to the current yield on bonds.

Q. GENERALLY DESCRIBE THE APPLICATION OF THE RISK PREMIUM METHOD USING AUTHORIZED ROES.

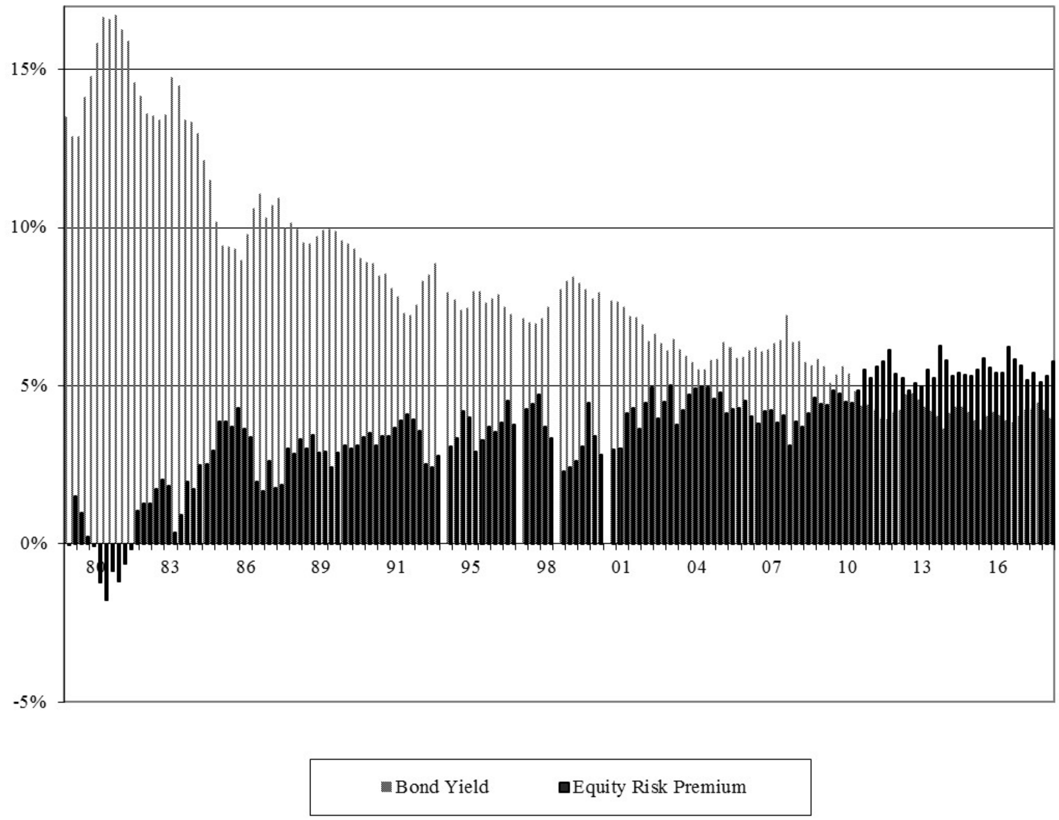
A. Application of the risk premium method based on authorized ROEs is predicated on the presumption that allowed returns reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final orders. A current risk premium is estimated based on the difference between past authorized ROEs and then-prevailing interest rates. This risk premium is then added to current interest rates to estimate the cost of equity.

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 the second quarter of 2019 are displayed in Schedule BHF-10. As shown there, the ROEs granted LDCs over this approximately 39-year period have averaged 11.58%, while the average single-A utility bond yield has averaged 7.98%, resulting in an average risk premium of 3.60%.

Q. IS THIS 3.60% AVERAGE RISK PREMIUM THE RELEVANT BENCHMARK FOR ESTIMATING THE COST OF EQUITY?

A. No. It is necessary to account for the fact that authorized ROEs do not move in lockstep with interest rates. In particular, when interest rate levels are relatively high, ROEs tend to be lower (i.e., equity risk premiums narrow), and when interest rates are relatively low, authorized ROEs are greater (i.e., equity risk premiums increase). This inverse relationship can be observed in the data contained in Schedule BHF-10, 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 REFLECT 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 single-A bond yields. The first was a simple linear regression between equity risk premiums and interest rates and the second equation adjusted for first order autocorrelation using the Prais-Winsten algorithm. Shown in the bottom portion of Schedule BHF-10, substituting the September 2019 yield of 3.37% on single-A public utility bonds into the regression equations indicates that the equity risk premium for an LDC at current interest rate levels is between approximately 5.76% and 5.94%.

Q. WHAT CURRENT COST OF EQUITY DOES THIS RISK PREMIUM IMPLY FOR THE GROUP OF LDCS?

A. Adding the 5.76% and 5.94% equity risk premiums developed on Schedule BHF-10 to the September 2019 yield on single-A utility bonds of 3.37% produces a current risk premium cost of equity range for LDC's of between 9.13% and 9.31%.

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 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 RETURNS ON BOOK EQUITY ARE OTHER LDCS EXPECTED TO EARN?

A. Schedule BHF-11 displays the return on book equity projected for each of the eight LDCs other than ONE Gas in the industry group for the 2018, 2019, and the 2022-2024 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 9.2% in 2019, 9.6% for 2020, and 10.5% for 2022-2024, with medians of 9.1%, 9.5%, and 10.1%, 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 9.1% and 10.1%, while the CAPM indicates a cost of equity range of between approximately 7.5% and 9.2%. Meanwhile, the risk premium method based on the authorized ROEs for LDCs and current interest rates indicates a cost of equity of between 9.1% and 9.3%, 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 9.1% to 10.1% range.

Q. WHAT ROE DO YOU RECOMMEND FOR THE PROPOSED CGSA?

A. As discussed earlier, the outlook for the U.S. economy is now more uncertain than ever, with global trade uncertainty and overhanging recession fears aggravating the normal uncertainties faced by the capital markets. Despite recent increases in stock prices and declines in interest rates, the cost of all capital, including common equity, is expected to be considerably higher over the next few years. So that TGS is able to offer investors a competitive return, attract capital on reasonable terms, and maintain its financial integrity, the allowed ROE should reflect the higher capital market requirements that are expected to exist when the proposed CGSA's rates will be in effect. The outlook for higher capital costs implies that the ROE for the proposed CGSA should be from the top of the cost of equity range. And while ONE Gas' debt and equity ratios are above and below, respectively, industry averages, they are well within LDCs norms, and warrant only a slight reduction in the cost of equity to account for lower financial risk. Therefore, I recommend an ROE for the proposed CGSA just below the top of my 9.1% to 10.1% cost of equity range, or 10.0%.

Q. HAVE YOU CONDUCTED ANY CHECKS OF REASONABLENESS OF YOUR RECOMMENDED ROE FOR THE PROPOSED CGSA?

A. Yes. The reasonableness of my recommended 10.0% ROE for the proposed CGSA can be evaluated by reviewing the ROEs previously granted by the Commission. The table below lists the ROEs authorized for the larger LDCs in Texas from 2015 through the present:

Date	Docket	Utility	ROE
8/25/2015	10432	CP Entex – TX Coast	10.00%
5/3/2016	10488	TGS – Gulf Coast	9.50%
9/27/2016	10506	TGS – West Texas	9.50%
11/15/2016	10526	TGS – Central Texas	9.50%
5/23/2017	10567	CP Entex -- Houston	9.60%
12/5/2017	10640	Atmos -- Dallas	10.10%
3/20/2018	10656	TGS -- RGV	9.50%
5/22/2018	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	9.75%
2/5/2019	10766	TGS -- BSSA	9.75%
5/21/2019	10779	Atmos – Mid-Tex	9.80%

As shown there, these allowed ROEs have ranged between 9.5% and 10.1%. Because my recommended 10.0% ROE falls within this range, the ROEs previously granted by the Commission over the last approximately five years support the reasonableness on my recommended 10.0% for the proposed CGSA.

VI. OVERALL RATE OF RETURN

Q. WHAT OVERALL RATE OF RETURN DO YOU RECOMMEND BE APPLIED TO THE RATE BASE OF THE PROPOSED CGSA?

A. I recommend that the Commission authorize an overall rate of return on the invested capital in the proposed CGSA of 7.93%. As developed in Schedule BHF-1, this overall rate of return is the result of combining ONE Gas' actual June 30, 2019 test year-end capital structure ratios of 37.88% debt and 62.12% equity with its average cost of debt of 4.53% and an ROE of 10.0%.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes, it does.

APPENDIX A

BRUCE H. FAIRCHILD

FINCAP, INC.
Financial Concepts and Applications
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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.

Participated as session chairman, moderator, and paper discussant at annual meetings of Financial Management Association, Southwestern Finance Association, American Finance Association, and other professional associations.

Visiting lecturer in Executive M.B.A program at the University of Stellenbosch Graduate Business School, Belleville, South Africa (1983 and 1984).

Associate Editor of *Austin Financial Digest*, 1974-1975. Wrote and edited a series of investment and economic articles published in a local investment advisory service.

Military

Texas Army National Guard, Feb. 1970 to Sep. 1976. Specialist 5th Class with duty assignments including recovery vehicle operator for armor unit and company clerk for finance unit.

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Monographs

“On the Use of Security Analysts’ Growth Projections in the DCF Model,” with William E. Avera, *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds., Institute for Study of Regulation (1982).

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“Energy Conservation in Existing Residences, Project Director for development of instruction manual and workshops promoting retrofitting of existing homes, *Governor's Office of Energy Resources* and *Department of Energy* (1977-1978).

“Linear Algebra,” “Calculus,” “Sets and Functions,” and “Simulation Techniques,” contributed to and edited four mathematics programmed learning texts for MBA students, *Texas Bureau of Business Research* (1975).

Articles and Notes

“How to Value Personal Service Practices,” with Keith Wm. Fairchild, *The Practical Accountant* (August 1989).

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“Capital Costs Within a Firm,” *Proceedings of the Southwestern Finance Association* (1977).

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Selected Papers and Presentations

"Federal Energy Regulatory Commission Audits of Common Carriers (Procedures for Audit Compliance)", Energy Transfer Accounting Employee Education, Dallas and Houston, Texas (December 2018).

"Perspectives on Texas Utility Regulation", TSCPA 2016 Energy Conference, Austin, Texas (May 16, 2016).

"Legislative Changes Affecting Texas Utilities," Texas Committee of Utility and Railroad Tax Representatives, Fall Meeting, Austin, Texas (September 1995).

"Rate of Return," "Origins of Information," Economics," and "Deferred Taxes and ITC's," New Mexico State University and National Association of Regulatory Utility Commissioners Public Utility Conferences on Regulation and the Rate-Making Process, Albuquerque, New Mexico (October 1983, 1984, 1985, 1986, 1987, 1988, 1990, 1991, 1992, 1994, and 1995, and September 1989); Pittsburgh, Pennsylvania (April 1993); and Baltimore, Maryland (May 1994 and 1995).

"Developing a Cost-of-Service Study," 1994 Texas Section American Water Works Association Annual Conference, Amarillo, Texas (March 1994).

"Financial Aspects of Cost of Capital and Common Cost Considerations," Kidder, Peabody & Co. Two-Day Rate Case Workshop for Regulated Utility Companies, New York, New York (June 1993).

"Cost-of-Service Studies and Rate Design," General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

"Rate Base and Revenue Requirements," The University of Texas Regulatory Institute Fundamentals of Utility Regulation, Austin, Texas (June 1989 and 1990).

"Determining the Cost of Capital in Today's Diversified Companies," New Mexico State University Public Utilities Course Part II, Advanced Analysis of Pricing and Utility Revenues, San Francisco, California (June 1990).

"Estimating the Cost of Equity," Oklahoma Association of Tax Representatives, Tulsa, Oklahoma (May 1990).

"Impact of Regulations," Business and the Economy, Leadership Dallas, Dallas, Texas (November 1989).

"Accounting and Finance Workshop" and "Divisional Cost of Capital," New Mexico State University Current Issues Challenging the Regulatory Process, Albuquerque, New Mexico (April 1985 and 1986) and Santa Fe, New Mexico (March 1989).

"Divisional Cost of Equity by Risk Comparability and DCF Analyses," NARUC Advanced Regulatory Studies Program, Williamsburg, Virginia (February 1988) and USTA Rate of Return Task Force, Chicago, Illinois (June 1988).

"Revenue Requirements," Revenue, Pricing, and Regulation in Texas Water Utilities, Texas Water Utilities Conference, Austin, Texas (August 1987 and May 1988).

"Rate Filing – Basic Ratemaking," Texas Gas Association Accounting Workshop, Austin, Texas (March 1988).

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"Revenue Requirements" and "Determining the Rate of Return", New Mexico State University Regulation and the Rate-Making Process, Southwestern Water Utilities Conference, Albuquerque, New Mexico (July 1986) and El Paso, Texas (November 1980).

"How to Evaluate Personal Service Practices," TSCPA CPE Exposition 1985, Houston and Dallas, Texas (December 1985).

"How to Start a Small Business – Accounting and Record Keeping," University of Texas Management Development Program, Austin, Texas (October 1984).

"Project Financing of Public Utility Facilities", TSCPA Conference on Public Utilities Accounting and Ratemaking, San Antonio, Texas (April 1984).

"Valuation of Closely-Held Businesses," Concho Valley Estate Planning Council, San Angelo, Texas (September 1982).

"Rating Regulatory Performance and Its Impact on the Cost of Capital," New Mexico State University Seminar on Regulation and the Cost of Capital, El Paso, Texas (May 1982).

"Effect of Inflation on Rate of Return," Cost of Capital Conference and Workshop, Pinehurst, North Carolina (April 1981).

"Original Cost Versus Current Cost Regulation: A Re-examination," Financial Management Association, New Orleans, Louisiana (October 1980).

"Capital Investment Analysis for Electric Utilities," The University of Texas at Dallas, Richardson, Texas (June 1980).

"The Determinants of Capital Costs to the Electric Utility Industry," with Cedric E. Grice, Southwestern Finance Association, San Antonio, Texas (March 1980).

"The Entrepreneur and Management: A Case Study," Small Business Administration Seminar, Austin, Texas (October 1979).

"Capital Budgeting by Public Utilities: A New Perspective," with W. Clifford Atherton, Jr., Financial Management Association, Boston, Massachusetts (October 1979).

"Issues in Regulated Industries – Electric Utilities," University of Texas at Dallas 4th Annual Public Utilities Conference, Dallas, Texas (July 1979).

"Investment Conditions and Strategies in Today's Markets," American Society of Women Accountants, Austin, Texas (January 1979).

"Attrition: A Practical Problem in Determining a Fair Return to Public Utility Companies," Financial Management Association, Minneapolis, Minnesota (October 1978).

"The Cost of Equity to Wholly-Owned Electric Utility Subsidiaries," with William L. Beedles, Financial Management Association, Minneapolis, Minnesota (October 1978).

"PUC Retrofitting Program," Texas Electric Cooperatives Spring Workshop, Austin, Texas (May 1978).

"The Economics of Regulated Industries," Consumer Economics Forum, Houston, Texas (November 1977).

"Public Utilities as Consumer Targets – Is the Pressure Justified?" University of Texas at Dallas 2nd Annual Public Utilities Conference, Dallas, Texas (July 1977).

APPENDIX B

BRUCE H. FAIRCHILD
SUMMARY OF TESTIMONY BEFORE REGULATORY AGENCIES

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
1.	Arkansas Electric Cooperative	Arkansas PSC	U-3071	Aug-80	Wholesale Rate Design
2.	East Central Oklahoma Electric Cooperative	Oklahoma CC	26925	Sep-80	Retail Rate Design
3.	Kansas Gas & Electric Company	Kansas CC	115379-U	Nov-80	PURPA Rate Design Standards
4.	Kansas Gas & Electric Company	Kansas CC	128139-U	May-81	Attrition
5.	City of Austin Electric Department	City of Austin	--	Jun-81	PURPA Rate Design Standards
6.	Tarrant County Water Control and Improvement District No. 1	Texas Water Commission	--	Oct-81	Wholesale Rate Design
7.	Owentown Gas Company	Texas RRC	2720	Jan-82	Revenue Requirements and Retail Rate Design
8.	Kansas Gas & Electric Company	Kansas CC	134792-U	Aug-82	Attrition
9.	Mississippi Power Company	Mississippi PSC	U-4190	Sep-82	Working Capital
10.	Lone Star Gas Company	Texas RRC	3757; 3794	Feb-83	Rate of Return on Equity
11.	Kansas Gas & Electric Company	Kansas CC	134792-U	Feb-83	Rate of Return on Equity
12.	Southwestern Bell Telephone Company	Oklahoma CC	28002	Oct-83	Rate of Return on Equity
13.	Morgas Company	Texas RRC	4063	Nov-83	Revenue Requirements
14.	Seagull Energy	Texas RRC	4541	Jul-84	Rate of Return
15.	Southwestern Bell Telephone Company	FCC	84-800	Nov-84	Rate of Return on Equity
16.	Kansas Gas & Electric Company, Kansas City Power & Light Company, and Kansas Electric Power Cooperatives	Kansas CC	142098-U; 142099-U; 142100-U	May-85	Nuclear Plant Capital Costs and Allowance for Funds Used During Construction
17.	Lone Star Gas Company	Texas RRC	5207	Oct-85	Overhead Cost Allocation
18.	Westar Transmission Company	Texas RRC	5787	Nov-85 Jan-86 Jul-86	Rate of Return, Rate Design, and Gas Processing Plant Economics
19.	City of Houston	Texas Water Commission	RC-022; RC-023	Nov-86	Line Losses and Known and Measurable Changes
20.	ENSTAR Natural Company	Alaska PUC	TA 50-4; R-87-2; U-87-2	Nov-86 May-87 May-87	Cost Allocation, Rate Design, and Tax Rate Changes
21.	Brazos River Authority	Texas Water Commission	RC-020	Jan-87	Revenue Requirements and Rate Design
22.	East Texas Industrial Gas Company	Texas RRC	5878	Feb-87	Revenue Requirements and Rate Design

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
23.	Seagull Energy	Texas RRC	6629	Jun-87	Revenue Requirements
24.	ENSTAR Natural Company	Alaska PUC	U-87-42	Jul-87 Sep-87 Sep-87	Cost Allocation, Rate Design, and Contracts
25.	High Plains Natural Gas Company	Texas RRC	6779	Sep-87	Rate of Return
26.	Hughes Texas Petroleum	Texas RRC	2-91,855	Jan-88	Interim Rates
27.	Cavallo Pipeline Company	Texas RRC	7086	Sep-88	Revenue Requirements
28.	Union Gas System, Inc.	Kansas CC	165591-U	Mar-89 Aug-89	Rate of Return
29.	ENSTAR Natural Gas Company	Alaska PUC	U-88-70	Mar-89	Cost Allocation and Bypass
30.	Morgas Co.	Texas RRC	7538	Aug-89	Rate of Return and Cost Allocation
31.	Corpus Christi Transmission Company	Texas RRC	7346	Sep-89	Revenue Requirements
32.	Amoco Gas Co.	Texas RRC	7550	Oct-89	Rate of Return and Cost Allocation
33.	Iowa Southern Utilities	Iowa Utilities Board	RPU-89-7	Nov-89 Mar-90	Rate of Return on Equity
34.	Southwestern Bell Telephone Company	FCC	89-624	Feb-90 Apr-90	Rate of Return on Equity
35.	Lower Colorado River Authority	Texas PUC	9427	Mar-90 Aug-90 Aug-90	Revenue Requirements
36.	Rio Grande Valley Gas Company	Texas RRC	7604	May-90	Consolidated FIT and Depreciation
37.	Southern Union Gas Company	El Paso PURB	--	Oct-90	Disallowed Expenses and FIT
38.	Iowa Southern Utilities	Iowa Utilities Board	RPU-90-8	Nov-90 Feb-91	Rate of Return on Equity
39.	East Texas Gas Systems	Texas RRC	7863	Dec-90	Revenue Requirements
40.	San Jacinto Gas Transmission	Texas RRC	7865	Dec-90	Revenue Requirements
41.	Southern Union Gas Company	Austin; Texas RRC	-- 7878	Feb-91 Feb-91	Rate of Return and Acquisition Adjustment
42.	Southern Union Gas Company	Port Arthur; Texas RRC	-- 8033	Mar-91 Aug-91 Oct-91	Rate of Return and Acquisition Adjustment
43.	Cavallo Pipeline Company	Texas RRC	8016	Jun-91	Revenue Requirements

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
44.	New Orleans Public Service Inc.	New Orleans City Council	CD-91-1	Jun-91 Mar-92	Rate of Return on Equity
45.	Houston Pipe Line Company	Texas RRC	8017	Jul-91	Rate of Return
46.	Southern Union Gas Company	El Paso PURB	--	Aug-91 Sep-91	Acquisition Adjustment
47.	Southwestern Gas Pipeline, Inc.	Texas RRC	8040	Jan-92 Feb-92	Rate Design and Settlement
48.	City of Fort Worth	Texas Water Commission	8748-A 9261-A	Mar-92 Aug-92 Dec-92 Oct-94 Nov-94	Interim Rates, Revenue Requirements, and Public Interest
49.	Southern Union Gas Company	Oklahoma Corp. Com.	--	Jun-92	Rate of Return
50.	Minnegasco	Minnesota PUC	G-008/GR-92-400	Jul-92 Dec-92	Rate of Return
51.	Guadalupe-Blanco River Authority	Texas PUC	11266	Sep-92	Cost Allocation and Bond Funds
52.	Dorchester Intra-State Gas System	Texas RRC	8111	Oct-92 Nov-92	Rate Impact of System Upgrade
53.	Corpus Christi Transmission Company GP and GPII	Texas RRC	8300 8301	Oct-92 Oct-92	Revenue Requirements
54.	East Texas Industrial Gas Company	Texas RRC	8326	Mar-93	Revenue Requirements
55.	Arkansas Louisiana Gas Company	Arkansas PSC	93-081-U	Apr-93 Oct-93	Rate of Return on Equity
56.	Texas Utilities Electric Company	Texas PUC	11735	Jun-93 Jul-93	Impact of Nuclear Plant Construction Delay
57.	Minnegasco	Minnesota PUC	G-008/GR-93-1090	Nov-93 Apr-94	Rate of Return
58.	Gulf States Utilities Company	Municipalities	--	May-94 Oct-94 Nov-94	Rate of Return on Equity
59.	Louisiana Power & Light Company	Louisiana PSC	U-20925	Aug-94 Feb-95	Rate of Return on Equity
60.	San Jacinto Gas Transmission	Texas RRC	8429	Sep-94	Revenue Requirements
61.	Cavallo Pipeline Company	Texas RRC	8465	Sep-94	Revenue Requirements
62.	Eastrans Limited Partnership	Texas RRC	8385	Oct-94	Revenue Requirements
63.	Gulf States Utilities Company	Louisiana PSC	U-19904	Oct-94	Rate of Return on Equity

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
64.	Entergy Services, Inc.	FERC	ER95-112-000	Mar-95 Nov-95	Rate of Return on Equity
65.	East Texas Gas Systems	Texas RRC	8435	Apr-95	Revenue Requirements
66.	System Energy Resources, Inc.	FERC	ER95-1042-000	May-95 Dec-95 Jan-96	Rate of Return on Equity
67.	Minnegasco	Minnesota PUC	G-008/GR-95-700	Aug-95 Dec-95	Rate of Return
68.	Entex	Louisiana PSC	U-21586	Aug-95	Rate of Return
69.	City of Fort Worth	Texas NRCC	SOAH 582-95-1084	Nov-95	Public Interest of Contract
70.	Seagull Energy Corporation	Texas RRC	8589	Nov-95	Revenue Requirements
71.	Corpus Christi Transmission Company LP	Texas RRC	8449	Feb-96	Revenue Requirements
72.	Missouri Gas Energy	Missouri PSC	GR-96-285	Apr-96 Sep-96 Oct-96	Rate of Return
73.	Entex	Mississippi PSC	96-UA-202	May-96	Rate of Return
74.	Entergy Gulf States, Inc.	Louisiana PSC	U-22084	May-96	Rate of Return on Equity (Gas)
75.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-96 Oct-96	Rate of Return on Equity
76.	American Gas Storage, L.P.	Texas RRC	8591	Sep-96	Revenue Requirements
77.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	Sep-96 Oct-96	Rate of Return on Equity
78.	Lone Star Pipeline and Gas Company	Texas RRC	8664	Oct-96 Jan-97	Rate of Return
79.	Entergy Arkansas, Inc.	Arkansas PSC	96-360-U	Oct-96 Sep-97	Rate of Return on Equity
80.	East Texas Gas Systems	Texas RRC	8658	Nov-96	Revenue Requirements
81.	Entergy Gulf States, Inc.	Texas PUC	16705	Nov-96 Jul-97	Rate of Return on Equity
82.	Eastrans Limited Partnership	Texas RRC	8657	Nov-96	Revenue Requirements
83.	Enserch Processing, Inc.	Texas RRC	8763	Nov-96	Interim Rates
84.	Entergy New Orleans, Inc.	City of New Orleans	UD-97-1	Feb-97 Mar-97 May-98	Rate of Return on Equity

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
85.	ENSTAR Natural Gas Company	Alaska PUC	U-96-108	Mar-97 Apr-97	Service Area Certificate
86.	San Jacinto Gas Transmission	Texas RRC	8741	Sep-97	Revenue Requirements
87.	Missouri Gas Energy	Missouri PSC	GR-98-140	Nov-97 Apr-98 May-98	Rate of Return
88.	Corpus Christi Transmission Company LP	Texas RRC	8762	Dec-97	Revenue Requirements
89.	Texas-New Mexico Power Company	Texas PUC	17751	Feb-98	Excess Cost Over Market
90.	Southern Union Gas Company	Texas RRC	8878	May-98	Rate of Return
91.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	May-98 Jul-98	Financial Integrity
92.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-98 Jul-98	Financial Integrity
93.	ACGC Gathering Company, LLC	Texas RRC	8896	Sep-98	Cost-based Rates
94.	American Gas Storage, L.P.	Texas RRC	8855	Oct-98	Revenue Requirements
95.	Duke Energy Intrastate Network	Texas RRC	8940	Jun-99	Rate of Return
96.	Aquila Energy Corporation	Texas RRC	8970	Aug-99	Revenue Requirements
97.	San Jacinto Gas Transmission	Texas RRC	8974	Sep-99	Revenue Requirements
98.	Southern Union Gas Company	El Paso PURB	--	Oct-99	Rate of Return
99.	TXU Lone Star Pipeline	Texas RRC	8976	Oct-99 Feb-00	Rate of Return
100.	Sharyland Utilities, L.P.	Texas PUC	21591	Nov-99	Rate of Return
101.	TXU Lone Star Gas Distribution	Texas RRC	9145	Apr-00 Aug-00	Rate of Return
102.	Rotherwood Eastex Gas Storage	Texas RRC	9136	May-00	Revenue Requirements
103.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9137	May-00	Revenue Requirements
104.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9138	Jul-00	Revenue Requirements
105.	East Texas Gas Systems	Texas RRC	9139	Jul-00	Revenue Requirements
106.	Eastrans Limited Partnership	Texas RRC	9140	Aug-00	Revenue Requirements
107.	Reliant Energy – Entex	City of Tyler	--	Oct-00	Rate of Return
108.	City of Fort Worth	Texas NRCC	SOAH 582-00-1092	Dec-00	CCN – Rates and Financial Ability
109.	Entergy Services, Inc.	FERC	RTO1-75	Dec-00	Rate of Return on Equity

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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

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Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
187.	Enbridge Pipelines (Southern Lights)	FERC	IS11-146-000	Jun 11 Nov 11	Rate of Return
188.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-___	Jul 11	Rate of Return
189.	Unocal Pipeline Company	Alaska RCA	TL126-___	Dec 11	Rate of Return
190.	Kansas Gas Service	Kansas CC	12-KGSC-835-RTS	May 12 Oct 12	Rate of Return
191.	ExxonMobil Pipeline Co.	Alaska RCA	TL-157-304	Jun 12	Rate of Return
192.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-149-301	Jul 12	Rate of Return
193.	Seaway Crude Pipeline Company	FERC	IS12-226-000	Aug 12 Feb 13	Rate of Return
194.	Cross Texas Transmission, LLC	Texas PUC	40604	Aug 12 Oct 12 Nov 12	Revenue Requirements
195.	Wind Energy Transmission Texas	Texas PUC	40606	Aug 12 Nov 12	Revenue Requirements
196.	Lone Star Transmission LLC	Texas PUC	40798	Nov 12	Revenue Requirements
197.	West Texas Gas Company	Texas RRC	10235	Jan 13	Rate of Return
198.	Cross Texas Transmission, LLC	Texas PUC	41190	Feb 13	Revenue Requirements
199.	ExxonMobil Pipeline Co.	Alaska RCA	TL-162-304	Apr 13	Rate of Return
200.	EasTrans,LLC	Texas RRC	10276	Jul 13	Rate of Return
201.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-152-301	Jul 13	Rate of Return
202.	BP Pipelines (Alaska) Inc.	Alaska RCA	TL-143-311	Sep 13	Rate of Return
203.	Wind Energy Transmission Texas	Texas PUC	41923	Oct 13	Revenue Requirements
204.	Oliktok Pipeline Company	Alaska RCA	P-13-013	Nov 13	Rate of Return
205.	Aqua Texas Southeast Region-Gray	Texas CEQ	2013-2007-UCR	Apr 14	Revenue Requirements
206.	Entergy Mississippi	Mississippi PSC	EC-123-0082	Jun 14	Rate of Return on Equity
207.	Westlake Ethylene Pipeline	Texas RRC	10358	Jul 14 Aug 15	Rates
208.	ExxonMobil Pipeline Co.	Alaska RCA	TL-164-304	Jul 14	Rate of Return
209.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-154-301	Aug 14	Rate of Return
210.	Enstar Natural Gas Company	Alaska RCA	TA-262-4	Sep 14 Jun 15	Revenue Requirements, Cost Allocation, and Rate Design

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Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
211.	Oliktok Pipeline Company	Alaska RCA	TL-44-334	Mar 15	Rate of Return
212.	Entergy Arkansas, Inc.	Arkansas PSC	15-0150U	Apr 15 Oct 15 Dec 15	Rate of Return on Equity
213.	Wind Energy Transmission Texas	Texas PUC	44746	Jun 15	Revenue Requirements
214.	Texas City	Texas RRC	10408	Jun 15 Nov 15	Pipeline Annual Assessment
215.	Oklahoma Natural Gas	Oklahoma CC	201500213	Jul 15 Nov 15	Rate of Return
216.	PTE Pipeline LLC	Alaska RCA	P-12-015	Sep 15	Rate of Return
217.	Northeast Transmission Development, LLC	FERC	ER16-453	Dec 15	Formula Rates
218.	Oncor Electric Delivery	Texas PUC	45188	Dec 15	Public Interest of Acquisition
219.	Corix Utilities (Texas)	Texas PUC	45418	Dec 15 Oct 16	Rate of Return
220.	Texas Gas Service	Texas RRC	10488	Dec 15	Rate of Return
221.	Texas Gas Service	Texas RRC	10506	Mar 16 Jun 16	Rate of Return
222.	Kansas Gas Service	Kansas CC	16-KGSG-491-RTS	May 16 Sep 16	Rate of Return on Equity
223.	Enstar Natural Gas Company	Alaska RCA	TA-285-4	Jun 16 Apr 17	Revenue Requirements, Cost Allocation, and Rate Design
224.	Texas Gas Service	Texas RRC	10526	Jun 16	Rate of Return
225.	West Texas LPG Pipeline	Texas RRC	10455	Aug 16 Jan 17	Rates and Rate of Return
226.	Liberty Utilities	Texas PUC	46356	Sep 16 Feb 17 Jun 17	Revenue Requirements and Rate of Return
227.	DesertLink LLC	FERC	ER17-135	Oct 16	Formula Rates
228.	Houston Pipe Line Co.	Texas RRC	10559	Nov 16	Revenue Requirements
229.	Texas Gas Service	Texas RRC	10656	Jun 17	Rate of Return
230.	Trans-Pecos Pipeline	Texas RRC	10646	Sep 17 Feb 18	Revenue Requirements
231.	Comanche Trail Pipeline	Texas RRC	10647	Sep 17 Feb 18	Revenue Requirements
232.	Alpine High Pipeline	Texas RRC	10665	Oct 17 Feb 18	Revenue Requirements

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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	P-18-0__	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	TCJA Tax Expense Reduction
251.	Colonial Pipeline Company.	FERC	OR18-7-002	Nov 19	Rate of Return

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OVERALL RATE OF RETURN

Capital Component	Percent of Total	Component Cost	Weighted Cost
Long-term Debt	37.88%	4.53%	1.71%
Common Equity	62.12%	10.00%	6.21%
Total	**100.00%**		**7.93%**

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ONE GAS, INC. CAPITAL STRUCTURE

	June 30, 2019		December 31, 2018		December 31, 2017		December 31, 2016		December 31, 2015		December 31, 2014	
	Amount	%	Amount	%	Amount	%	Amount	%	Amount	%	Amount	%
	(000's)		(000's)		(000's)		(000's)		(000's)		(000's)	
Long-term Debt:												
Current Maturities	-		-		-		7		7		6	
Long-term Debt	1,285,811		1,285,483		1,193,257		1,192,446		1,201,305		1,201,311	
Total Long-term Debt	1,285,811	37.9%	1,285,483	38.6%	1,193,257	37.8%	1,192,453	38.7%	1,201,312	39.5%	1,201,317	40.1%
Shareholders' Equity:	2,108,463	62.1%	2,042,656	61.4%	1,960,209	62.2%	1,888,280	61.3%	1,841,555	60.5%	1,794,037	59.9%
Total	**3,394,274**	**100.00%**	**3,328,139**	**100.00%**	**3,153,466**	**100.00%**	**3,080,733**	**100.00%**	**3,042,867**	**100.00%**	**2,995,354**	**100.00%**

Sources: ONE Gas, Inc. Forms 10-K and 10-Q (June 30, 2019).

LDC PROXY GROUP CAPITAL STRUCTURE RATIOS (a)

	Fiscal Year-end 2018		Fiscal Year-end 2017		Fiscal Year-end 2016		Fiscal Year-end 2015		Fiscal Year-end 2014	
Company	**L.T. Debt**	**Equity**	**L.T. Debt**	**Equity**	**L.T. Debt**	**Equity**	**L.T. Debt**	**Equity**	**L.T. Debt**	**Equity**
Atmos Energy	34.3%	65.7%	44.0%	56.0%	38.7%	61.3%	43.5%	56.5%	44.3%	55.7%
Chesapeake Utilities	37.9%	62.1%	28.9%	71.1%	23.5%	76.5%	29.4%	70.6%	34.5%	65.5%
New Jersey Resources	45.4%	54.6%	44.6%	55.4%	47.7%	52.3%	43.2%	56.8%	38.2%	61.8%
NiSource	55.3%	44.7%	63.5%	36.5%	59.8%	40.2%	60.7%	39.3%	56.9%	43.1%
Northwest Natural Gas	48.1%	51.9%	47.9%	52.1%	44.4%	55.6%	42.5%	57.5%	44.8%	55.2%
South Jersey Industries	(b)	(b)	48.5%	51.5%	38.5%	61.5%	49.2%	50.8%	48.0%	52.0%
Southwest Gas	48.3%	51.7%	49.8%	50.2%	48.2%	51.8%	49.3%	50.7%	52.4%	47.6%
Spire	45.7%	54.3%	50.0%	50.0%	50.9%	49.1%	53.0%	47.0%	55.1%	44.9%
LDC GROUP AVERAGE	**45.0%**	**55.0%**	**47.2%**	**52.9%**	**44.0%**	**56.0%**	**46.4%**	**53.7%**	**46.8%**	**53.2%**
Minimum	34.3%	44.7%	28.9%	36.5%	23.5%	40.2%	29.4%	39.3%	34.5%	43.1%
Maximum	55.3%	65.7%	63.5%	71.1%	59.8%	76.5%	60.7%	70.6%	56.9%	65.5%

(a) *The Value Line Investment Survey* (August 30, 2019).
(b) Capital structure ratios distorted due to major acquisitions during 2018 financed principally with debt.

DCF MODEL -- DIVIDEND YIELD

Company	Expected Dividend (a)	Price (b)	Dividend Yield (c)
Atmos Energy	$ 2.24	$ 111.44	2.01%
Chesapeake Utilities	$ 1.65	$ 94.31	1.75%
New Jersey Resources	$ 1.25	$ 45.01	2.78%
NiSource Inc.	$ 0.80	$ 29.57	2.71%
Northwest Natural Gas	$ 1.90	$ 71.25	2.67%
ONE Gas	$ 2.12	$ 92.76	2.29%
South Jersey Industries	$ 1.23	$ 32.68	3.76%
Southwest Gas	$ 2.25	$ 90.92	2.47%
Spire Inc.	$ 2.37	$ 86.23	2.75%
AVERAGE			**2.58%**
MEDIAN			**2.67%**

(a) *The Value Line Investment Survey* (October 11, 2019).
(b) Fidelity Investments Stock Research "Price History" (Average of daily September 2019 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 (a)**	**5-Year (a)**
Atmos Energy	7.5%	7.0%	7.0%	6.5%	10.0%
Chesapeake Utilities	9.0%	N/R	7.0%	9.0%	8.0%
New Jersey Resources	3.5%	N/R	8.0%	7.0%	5.5%
NiSource Inc.	12.5%	4.7%	5.4%	NMF	NMF
Northwest Natural Gas	NMF	4.0%	5.0%	NMF	NMF
ONE Gas	8.0%	N/R	6.1%	N/A	N/A
South Jersey Industries	10.5%	N/R	8.5%	1.5%	NMF
Southwest Gas	9.0%	8.2%	7.3%	7.0%	4.5%
Spire Inc.	5.5%	3.2%	5.5%	4.0%	7.5%
AVERAGE	**8.2%**	**5.4%**	**6.6%**	**5.8%**	**7.1%**
MEDIAN	**8.5%**	**4.7%**	**7.0%**	**6.8%**	**7.5%**

(a) *The Value Line Investment Survey* (August 30, 2019).
(b) *Thomson Reuters Stock Reports* (Retrieved October 12, 2019).
(c) Zacks *Detailed Estimates* (Retrieved October 12, 2019).

NMF -- No meaningful figure. N/A -- Not applicable. N/R -- Not reported.

DCF MODEL -- SUSTAINABLE GROWTH RATES

	2022-2024 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	2018	Proj. 22-24	Retention Ratio	Return on Equity	"b x r"	2022-2024 Market-to-Book Ratio	Growth Rate in Shares	"s"	"v"	"s x v"	Sustainable Growth
Atmos Energy	$ 5.60	$ 2.70	$ 56.05	$ 127.50	111.27	145.00	51.8%	10.0%	5.2%	2.27	5.4%	12.4%	56.0%	6.9%	12.1%
Chesapeake Utilities	$ 5.00	$ 2.15	$ 49.00	$ 120.00	16.38	20.00	57.0%	10.2%	5.8%	2.45	4.1%	10.0%	59.2%	5.9%	11.7%
New Jersey Resources	$ 2.50	$ 1.33	$ 21.85	$ 42.50	87.69	89.00	46.8%	11.4%	5.4%	1.95	0.3%	0.6%	48.6%	0.3%	5.6%
NiSource Inc.	$ 1.80	$ 1.20	$ 20.00	$ 30.00	372.36	350.00	33.3%	9.0%	3.0%	1.50	-1.2%	-1.8%	33.3%	-0.6%	2.4%
Northwest Natural Gas	$ 3.50	$ 2.20	$ 29.40	$ 77.50	28.88	32.00	37.1%	11.9%	4.4%	2.64	2.1%	5.5%	62.1%	3.4%	7.8%
ONE Gas	$ 4.75	$ 2.65	$ 47.90	$ 117.50	52.57	55.00	44.2%	9.9%	4.4%	2.45	0.9%	2.2%	59.2%	1.3%	5.7%
South Jersey Industries	$ 2.40	$ 1.40	$ 20.00	$ 40.00	85.51	100.00	41.7%	12.0%	5.0%	2.00	3.2%	6.4%	50.0%	3.2%	8.2%
Southwest Gas	$ 5.80	$ 2.60	$ 58.60	$ 92.50	53.03	58.00	55.2%	9.9%	5.5%	1.58	1.8%	2.9%	36.6%	1.0%	6.5%
Spire Inc.	$ 5.00	$ 2.67	$ 54.20	$ 90.00	50.67	55.00	46.6%	9.2%	4.3%	1.66	1.7%	2.7%	39.8%	1.1%	5.4%
AVERAGE									**4.8%**					**2.5%**	**7.3%**
MEDIAN									**5.0%**					**1.3%**	**6.5%**

(a) *The Value Line Investment Survey* (August 30, 2019).

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DCF MODEL -- OTHER PROJECTED AND HISTORICAL GROWTH RATES

	Net Book Value (a)			Dividends per Share (a)			Price per Share		
	Pro-	Historical		Pro-	Historical		Pro-	Historical (b)	
Company	**jected**	**10-Year**	**5-Year**	**jected**	**10-Year**	**5-Year**	**jected (a)**	**10-Year**	**5-Year**
Atmos Energy	7.0%	5.5%	7.0%	7.0%	3.5%	5.5%	3.4%	14.6%	17.6%
Chesapeake Utilities	9.0%	10.0%	10.5%	9.0%	5.0%	6.0%	6.2%	16.5%	16.7%
New Jersey Resources	6.5%	7.0%	8.0%	4.0%	7.5%	6.5%	-1.4%	9.5%	12.0%
NiSource	7.5%	NMF	NMF	9.0%	NMF	NMF	0.4%	18.5%	13.7%
Northwest Natural Gas	1.0%	2.0%	N/R	2.5%	2.5%	1.0%	2.1%	5.3%	10.2%
ONE Gas	4.5%	N/A	N/A	8.5%	N/A	N/A	6.1%	N/A	20.7%
South Jersey Industries	4.5%	6.5%	6.0%	4.0%	8.0%	6.0%	5.2%	6.2%	3.5%
Southwest Gas	7.5%	5.5%	6.0%	5.0%	8.5%	10.5%	0.4%	13.4%	12.3%
Spire Inc.	4.0%	7.5%	8.0%	4.0%	4.0%	5.0%	1.1%	10.3%	12.5%
AVERAGE	**5.7%**	**6.3%**	**7.6%**	**5.9%**	**5.6%**	**5.8%**	**2.6%**	**11.8%**	**13.2%**
MEDIAN	**6.5%**	**6.5%**	**7.5%**	**5.0%**	**5.0%**	**6.0%**	**2.1%**	**11.9%**	**12.5%**

(a) *The Value Line Investment Survey* (August 30, 2019).
(b) Fidelity Investments Stock Research "Price History" (Average of daily September 2014 and September 21-October 20, 2009 closing prices).

NMF -- No meaningful figure. N/A -- Not applicable. N/R -- Not reported.

CAPITAL ASSET PRICING MODEL

	Historical Rates of Return (a)	**Forward-Looking Rates of Return (b)**
Market Required Rate of Return	11.88%	11.71%
Long-term Government Bond Return (a)(c)	4.97%	2.12%
Market Risk Premium (d)	6.91%	9.59%
LDC Group Beta (e)	0.66	0.66
LDC Group Risk Premium (f)	4.53%	6.29%
Risk-free Rate of Interest (c)	2.12%	2.12%
Theoretical CAPM Cost of Equity Estimate (g)	6.65%	8.41%
Size Premium (e)	0.82%	0.82%
CAPM Cost of Equity Estimates (h)	**7.47%**	**9.23%**

(a) Duff & Phelps*; 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits.*
(b) Calculated by applying DCF model applied to S&P 500 firms paying dividends (September 26, 2019):

Expected Dividend Yield		2.41%
Projected Earnings Growth Rate:		
Value Line	10.12%	
I/B/E/S	8.88%	
Zacks	8.91%	
Average		9.31%
Market Required Rate of Return		11.71%

(c) September 2019 yield on 30-year U.S. Treasury bonds (Federal Reserve). 2.12%
(d) Market Required Rate of Return minus Long-term Government Bond Return.
(e) Schedule BHF-9.
(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.

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BOND RATINGS, BETA, MARKET CAPITALIZATION, AND SIZE PREMIUMS

Risk Measures

Company	Bond Rating Moody's (a)	Bond Rating S&P (b)	Beta (c)	Market Capitalization (millions) (c)
Atmos Energy	A2	A	0.60	$ 13,000
Chesapeake Utilities	N/R	N/R	0.65	$ 1,500
New Jersey Resources	Aa3	N/R	0.70	$ 4,000
NiSource Inc.	Baa2	BBB+	0.55	$ 10,900
Northwest Natural Gas	A2	A+	0.60	$ 2,200
ONE Gas	A2	A	0.65	$ 4,800
South Jersey Industries	A3	BBB	0.80	$ 2,900
Southwest Gas	Baa1	BBB+	0.70	$ 4,800
Spire Inc.	Baa2	A-	0.65	$ 4,100
LDC GROUP AVERAGE	**A3**	**A-**	**0.66**	**$ 5,356**

CRSP Deciles Size Premiums (d)

	Market Capitalization of Smallest Company (in millions)		Market Capitalization of Largest Company (in millions)	Size Premium (Return in Excess of CAPM)
Decile				
Mid-Cap 3-5	$ 2,996.003	-	$ 13,455.802	0.91%
Low Cap 6-8	730.047	-	2,992.251	1.60%
Micro-Cap 9-10	2.455	-	727.843	3.37%
Breakdown of Deciles 1-10				
1-Largest	$ 29,428.909	-	$1,073,390.566	-0.29%
2	13,512.960	-	29,022.867	0.50%
3	7,275.967	-	13,455.802	0.84%
4	4,504.066	-	7,254.230	0.82%
5	2,996.003	-	4,503.549	1.26%
6	1,961.831	-	2,992.251	1.54%
7	1,292.791	-	1,960.201	1.58%
8	730.047	-	1,292.224	1.82%
9	325.360	-	727.843	2.42%
10- Smallest	2.455	-	321.578	5.23%
Breakdown of CRSP 10th Decile				
10a	$ 185.418	-	$ 321.578	3.74%
10w	250.270	-	321.578	2.88%
10x	185.418	-	250.248	4.71%
10b	$ 2.455	-	$ 184.785	8.23%
10y	109.462	-	184.785	6.85%
10z	2.455	-	109.406	11.16%

(a) Moody's.com (Retreived September 20, 2019).
(b) StandardandPoors.com (Retreived September 20, 2019)
(c) *The Value Line Investment Survey* (August 30, 2019).
(d) *Duff & Phelps; 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits.*

RISK PREMIUM METHOD

Year	Qtr.	Allowed ROE (a)	Single-A Utility Bond Yield (b)	Risk Premium	Year	Qtr.	Allowed ROE (a)	Single-A Utility Bond Yield (b)	Risk Premium
1980	1	13.45%	13.49%	-0.04%	2000	1	10.71%	8.29%	2.42%
	2	14.38%	12.87%	1.51%		2	11.08%	8.45%	2.63%
	3	13.87%	12.88%	0.99%		3	11.33%	8.25%	3.08%
	4	14.35%	14.11%	0.24%		4	12.50%	8.03%	4.47%
1981	1	14.69%	14.77%	-0.08%	2001	1	11.16%	7.74%	3.42%
	2	14.61%	15.82%	-1.21%		2 (c)	10.75%	7.93%	2.82%
	3	14.86%	16.65%	-1.79%		4	10.65%	7.68%	2.97%
	4	15.70%	16.57%	-0.87%	2002	1	10.67%	7.65%	3.02%
1982	1	15.55%	16.72%	-1.17%		2	11.64%	7.50%	4.14%
	2	15.62%	16.26%	-0.64%		3	11.50%	7.19%	4.31%
	3	15.72%	15.88%	-0.16%		4	10.78%	7.15%	3.63%
	4	15.62%	14.56%	1.06%	2003	1	11.38%	6.93%	4.45%
1983	1	15.41%	14.15%	1.26%		2	11.36%	6.40%	4.96%
	2	14.84%	13.58%	1.26%		3	10.61%	6.64%	3.97%
	3	15.24%	13.52%	1.72%		4	10.84%	6.35%	4.49%
	4	15.41%	13.38%	2.03%	2004	1	11.10%	6.09%	5.01%
1984	1	15.39%	13.56%	1.83%		2	10.25%	6.48%	3.77%
	2	15.07%	14.72%	0.35%		3	10.37%	6.13%	4.24%
	3	15.37%	14.47%	0.90%		4	10.66%	5.94%	4.72%
	4	15.33%	13.38%	1.95%	2005	1	10.65%	5.74%	4.91%
1985	1	15.03%	13.31%	1.72%		2	10.52%	5.52%	5.00%
	2	15.44%	12.95%	2.49%		3	10.47%	5.51%	4.96%
	3	14.64%	12.11%	2.53%		4	10.40%	5.82%	4.58%
	4	14.44%	11.49%	2.95%	2006	1	10.63%	5.85%	4.78%
1986	1	14.05%	10.18%	3.87%		2	10.50%	6.37%	4.13%
	2	13.28%	9.41%	3.87%		3	10.45%	6.19%	4.26%
	3	13.09%	9.39%	3.70%		4	10.14%	5.86%	4.28%
	4	13.62%	9.31%	4.31%	2007	1	10.44%	5.90%	4.54%
1987	1	12.61%	8.96%	3.65%		2	10.12%	6.09%	4.03%
	2	13.13%	9.77%	3.36%		3	10.03%	6.22%	3.81%
	3	12.56%	10.61%	1.95%		4	10.27%	6.08%	4.19%
	4	12.73%	11.05%	1.68%	2008	1	10.38%	6.15%	4.23%
1988	1	12.94%	10.32%	2.62%		2	10.17%	6.32%	3.85%
	2	12.48%	10.71%	1.77%		3	10.49%	6.42%	4.07%
	3	12.79%	10.94%	1.85%		4	10.34%	7.23%	3.11%
	4	12.98%	9.98%	3.00%	2009	1	10.24%	6.37%	3.87%
1989	1	12.99%	10.13%	2.86%		2	10.11%	6.39%	3.72%
	2	13.25%	9.94%	3.31%		3	9.88%	5.74%	4.14%
	3	12.56%	9.53%	3.03%		4	10.27%	5.66%	4.61%
	4	12.94%	9.50%	3.44%	2010	1	10.24%	5.83%	4.41%
1990	1	12.60%	9.72%	2.88%		2	9.99%	5.61%	4.38%
	2	12.81%	9.91%	2.90%		3	9.93%	5.09%	4.84%
	3	12.34%	9.93%	2.41%		4	10.09%	5.34%	4.75%
	4	12.77%	9.89%	2.88%	2011	1	10.10%	5.60%	4.50%
1991	1	12.69%	9.58%	3.11%		2	9.85%	5.38%	4.47%
	2	12.53%	9.50%	3.03%		3	9.65%	4.81%	4.84%
	3	12.43%	9.33%	3.10%		4	9.88%	4.37%	5.51%
	4	12.38%	9.02%	3.36%	2012	1	9.63%	4.39%	5.24%
1992	1	12.42%	8.91%	3.51%		2	9.83%	4.23%	5.60%
	2	11.98%	8.86%	3.12%		3	9.75%	3.98%	5.77%
	3	11.87%	8.47%	3.40%		4	10.07%	3.92%	6.15%
	4	11.94%	8.53%	3.41%	2013	1	9.57%	4.18%	5.39%
1993	1	11.75%	8.07%	3.68%		2	9.47%	4.23%	5.24%
	2	11.71%	7.81%	3.90%		3	9.60%	4.74%	4.86%
	3	11.39%	7.28%	4.11%		4	9.83%	4.76%	5.07%
	4	11.15%	7.22%	3.93%	2014	1	9.54%	4.56%	4.98%
1994	1	11.12%	7.55%	3.57%		2	9.84%	4.32%	5.52%
	2	10.81%	8.29%	2.52%		3	9.45%	4.20%	5.25%
	3	10.95%	8.51%	2.44%		4	10.28%	4.03%	6.25%
	4 (c)	11.64%	8.87%	2.77%	2015	1	9.47%	3.66%	5.81%
1995	2	11.00%	7.93%	3.07%		2	9.43%	4.10%	5.33%
	3	11.07%	7.72%	3.35%		3	9.75%	4.35%	5.40%
	4	11.56%	7.37%	4.19%		4	9.68%	4.35%	5.33%
1996	1	11.45%	7.44%	4.01%	2016	1	9.48%	4.18%	5.30%
	2	10.88%	7.98%	2.90%		2	9.42%	3.90%	5.52%
	3	11.25%	7.96%	3.29%		3	9.47%	3.61%	5.86%
	4	11.32%	7.62%	3.70%		4	9.60%	4.04%	5.56%
1997	1	11.31%	7.76%	3.55%	2017	1	9.60%	4.18%	5.42%
	2	11.70%	7.88%	3.82%		2	9.47%	4.06%	5.41%
	3	12.00%	7.49%	4.51%		3	10.14%	3.91%	6.23%
	4 (c)	11.01%	7.25%	3.76%		4	9.68%	3.84%	5.84%
1998	2	11.37%	7.12%	4.25%	2018	1	9.68%	4.03%	5.65%
	3	11.41%	6.99%	4.42%		2	9.43%	4.24%	5.19%
	4	11.69%	6.97%	4.72%		3	9.69%	4.28%	5.41%
1999	1	10.82%	7.11%	3.71%		4	9.53%	4.45%	5.08%
	2 (c)	10.82%	7.48%	3.34%	2019	1	9.55%	4.25%	5.30%
	4	10.33%	8.05%	2.28%		2	9.73%	3.96%	5.77%
					Average		**11.58%**	**7.98%**	**3.60%**

Unadusted:

Risk Premium = Intercept + (Slope X Interest Rate) (d)

RP	=	0.07331	+	-0.46767	X	3.37%
RP	=	0.07331	+	-0.01576		
RP	**=**	**5.76%**				

Adjusted (Using Iterative Prais-Winsten algorithm):

Risk Premium = Intercept + (Slope X Interest Rate) (d)

RP	=	0.07663	+	-0.51022	X	3.37%
RP	=	0.07663	+	-0.01719		
RP	**=**	**5.94%**				

(a) Regulatory Research Associates, Inc., Major Rate Case Decisions, (July 22, 2019, January 24, 2002, January 18, 1995, and January 16, 1990).
(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 single-A utlity bond yield for September 2019.

COMPARABLE EARNINGS METHOD

Company	Projected Earned Return on Book Equity (a) 2019	2020	2022-24
Atmos Energy	9.5%	9.4%	10.0%
Chesapeake Utilities	10.4%	10.3%	10.2%
New Jersey Resources	11.7%	12.2%	11.4%
NiSource Inc.	8.9%	8.3%	9.0%
Northwest Natural Gas	9.1%	9.7%	11.9%
South Jersey Industries	7.0%	9.5%	12.0%
Southwest Gas	9.1%	9.4%	9.9%
Spire	7.9%	7.7%	9.2%
AVERAGE	**9.2%**	**9.6%**	**10.5%**
MEDIAN	**9.1%**	**9.5%**	**10.1%**

(a) *The Value Line Investment Survey* (August 30, 2019).

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF BRUCE FAIRCHILD

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

1. "My name is Bruce Fairchild. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as a Principal in Financial Concepts and Applications, Inc., a firm engaged in financial, economic and policy consulting to business and government. 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.

Bruce Fairchild

SUBSCRIBED AND SWORN TO BEFORE ME by the said Bruce Fairchild on this 2nd day of December, 2019

BRYAN ANDERSON
NOTARY PUBLIC STATE OF TEXAS
MY COMM. EXP. 11/02/2021
NOTARY ID 12592363-3

Notary Public in and for the State of Texas

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

CRYSTAL D. DRUMM

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF CRYSTAL D. DRUMM

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Crystal D. Drumm (Turner), and my business address is 15 East Fifth Street, Tulsa, Oklahoma.

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

A. I am employed by ONE Gas, Inc. ("ONE Gas") as a Rates Specialist. I am testifying on behalf of Texas Gas Service Company ("TGS" or the "Company"), which is a division of ONE Gas.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Master's of Science Degree in Quantitative Financial Economics from Oklahoma State University and a Bachelor's of Science Degree in Statistics with minors in Mathematics and Spanish as well as an Honors Degree with International Emphasis from Oklahoma State University. I began my career with ONE Gas in May 2014 as a Rates Analyst I. In May 2016, I was promoted to a Rates Analyst II and in April 2018, I was promoted to Rates Specialist. Prior to joining ONE Gas, I worked as a Risk Analyst for Seminole Energy Services, LLC from February 2012 to April 2014. From May 2011 to January 2012, I worked as a Technical Sales Support Intern for Enogex. In my current position at ONE Gas, my responsibilities include calculating, researching and analyzing accounting related issues, analyzing and preparing studies, reports, and testimony related to cost of service, rate design, alternative ratemaking, and depreciation.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY JURISDICTIONS?

A. Yes, I have filed testimony in proceedings before the Oklahoma Corporation Commission, the Kansas Corporation Commission and the Railroad Commission of Texas ("Commission"). A list of the dockets in which I have testified is provided as Exhibit CDD-1.

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.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents and supports the class cost of service ("CCOS") study and class revenue allocation based on the CCOS study results I prepared for the proposed consolidated Central-Gulf Service Area ("CGSA"). Consistent with the Company's request, should consolidation not be approved, I have also prepared individual CCOS studies and their respective class revenue allocations for the Central Texas Service Area ("CTSA") and the Gulf Coast Service Area ("GCSA").[1] I support the CCOS study tabs listed below in each of the integrated models.

Study Summary
Study Summary for Rev. Alloc.

[1] City of Beaumont customers are included in the GCSA CCOS study.

Classified Rate Base
Classified Cost of Service
Classification Factors
Allocated Rate Base
Allocated Cost of Service
Allocation Factors
Depreciation and Reserve WP
Administrative & General WP
Selected Data WP
903 Factors
904 Factors
Bill Determinants Summary_CTSA
Customer Deposit Factors
Mains Study Summary
Meter & Regulator Factors
Odorization Summary
Peak Demand
Service Charges Summary
Service Line Factors
Summary of As Adj Revs_CTSA
Selected Data WP 2
Selected Data WP 3
Class Revenue Allocation

II. CLASS COST OF SERVICE STUDY

Q. WHAT IS A CLASS COST OF SERVICE STUDY?

A. A CCOS study is an analysis to fully allocate 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 require that each customer class pay the cost to serve their class, and interclass inequities can often arise over time. Interclass inequities can be due to changes in customer class characteristics, adjustments to rates from interim rate filings, and changes in a company's investment and expenses. In identifying both fixed and variable costs, the CCOS study also provides information that is useful in setting monthly customer charges to recover fixed costs and setting usage charges to recover variable costs for each class. Please see the direct testimony of Company witness Paul Raab discussing TGS'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 that 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 TYPICALLY PERFORMED IN A GAS UTILITY CCOS STUDY.

A. A gas utility CCOS study typically consists of three functions: (1) production and storage, (2) transmission, and (3) distribution. The production and storage function includes the costs of gas wells, gas field lines, and gas processing plants. Transmission costs involve the cost of facilities and related expenses associated with delivering gas from production and storage areas to city gates, which are the points at which the gas enters a utility's distribution system. Distribution costs refer to costs and expenses associated with delivering gas from city gates to end use customers and providing associated services such as meter reading, billing, and customer service.

Q. PLEASE DISCUSS THE CLASSIFICATIONS USED IN THE CLASSIFICATION STEP.

A. There are four classifications that are used in the second step of a CCOS study. These classifications are (1) customer-related, (2) demand-related, (3) commodity-related, and (4) revenue-related costs. I describe each of these four classifications below.

Customer-related costs are those costs that vary with the number of customers or customer locations served, regardless of whether or not any gas is used. Examples include the cost of a meter at a customer's location and the portion of the cost of distribution mains associated with reaching the customer's location. These costs do not depend on the amount of gas used over the course of the year or at peak periods but rather are incurred to provide customer access to gas service.

Demand-related costs are defined as those costs that depend on the maximum delivery requirements of the gas system. These delivery requirements are measured by usage at the time of the system's peak. The system's peak usage is based on historically extreme winter weather conditions that relate to sizing facilities that are weather dependent. An example of demand costs is the portion of the cost of distribution mains associated with the sizing of distribution mains to meet peak loads. Transmission costs and related expenses are another example of demand costs.

Commodity-related costs are defined as those costs that vary with the amount of gas that is delivered to customers. Odorization cost and related expenses are examples of commodity-related costs. [2]

Revenue-related costs are those costs that vary directly with the utility's gross revenue. Revenue-related taxes are examples of revenue-related expenses. In the CCOS study in this case, I have classified revenue-related elements as customer-related and allocated them based on revenues in the allocation step of the study, rather than using a separate revenue classification. The allocated cost results will be the same with this approach as with the use of the separate revenue-based classification.

[2] Purchased gas expense is also commodity-related, but this expense is removed in determining a company's revenue requirement and is not part of a CCOS study when the expense is separately recovered through a pass-through mechanism.

Q. DO SOME OF THE COST COMPONENTS REQUIRE COMBINATIONS OF CLASSIFICATIONS?

A. Yes, some cost components require combinations of classifications. While many cost of service components fall into a single classification, several components involve more than one classification category which require 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. 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 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, interest on customer deposits and bad debt expense are directly assigned to the residential class and, to the extent practicable, to each of the non-residential classes.[3]

Q. PLEASE DISCUSS THE DIFFERENT TYPES OF ALLOCATIONS USED IN THE STUDY.

A. 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

[3] The test year amounts for these cost of service components are available and direct assignments are made to the residential, commercial, industrial, public authority and compressed natural gas classes, including commercial, industrial, public authority, and compressed natural gas transportation service. Within the non-residential classes, allocations are required to split the assigned amounts between public schools space heating and the public authority class. For each of these classes, assigned service charge revenue, customer deposits and interest on customer deposits are allocated based on relative customer counts and bad debt expense is allocated based on relative margin.

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.

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. HAS THE COMMISSION RECENTLY REVIEWED PRIOR CCOS STUDIES CONDUCTED BY THE COMPANY USING THE 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 Gas Utilities Docket ("GUD") No. 10506 and included the following Findings of Fact in the Final Order:

> 98. TGS's class cost of service ("CCOS") study is reasonable to use.
>
> 99. TGS's CCOS study classifies and allocates costs in a fair, just, and reasonable manner.[4]

[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 at 8-9 (Sept. 27, 2016).

Q. DID YOU APPLY THE SAME METHODS, CLASSIFICATION AND ALLOCATION FACTORS THAT WERE USED BY THE COMPANY IN GUD NO. 10506 IN PREPARING THE CCOS STUDY IN THIS STATEMENT OF INTENT?

A. Yes, I used the same methods, classification and allocation factors in this Statement of Intent as the Company used in the CCOS study that was found reasonable in GUD No. 10506.

Q. ARE THESE SAME METHODS, CLASSIFICATION AND ALLOCATION FACTORS CONSISTENT WITH THE CCOS STUDIES THAT WERE CONDUCTED IN RECENT CTSA AND GCSA RATE CASES?

A. Yes, these are the same methods, classification and allocation factors used in the CCOS studies conducted in recent CTSA and GCSA rate cases.

Q. PLEASE DESCRIBE EXHIBIT CDD-2, WHICH IS THE CCOS STUDY IN THIS CASE.

A. The CCOS study results for the proposed CGSA are provided in Exhibit CDD-2.[5] Page 1 of Exhibit CDD-2 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 CDD-2, 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.

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[5] On Exhibit CDD-2, the transportation cost of service results have been combined into the corresponding gas sales customer classes and are shown on line 4. In addition, cogeneration cost of service results have been combined into the public authority class.

Q. WHAT ADDITIONAL REVENUES ARE INCLUDED IN THE REVENUE ALLOCATION?

A. To determine how much revenue must be recovered through recurring monthly customer and usage charges from each class to meet the cost of service, revenue from other sources must be credited to the cost of service. The revenue credit is comprised of revenue from service charges, special contracts, 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 CDD-2. 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 CDD-2 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 currently has a revenue-to-cost ratio less than one [line 10, column (c)], indicating that the class is paying less than its cost of service today. The revenue-to-cost ratios of the non-residential classes are all greater than one [line 10, columns (d) through (h)], 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 CDD-2.

A. Pages 3 through 15 of Exhibit CDD-2 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 CDD-2 show the classification of the individual components of the cost of service, or revenue requirement. Exhibit CDD-2, pages 10 through 15 provide the classification factors used on pages 3 through 9 of Exhibit CDD-2.

Q. PLEASE EXPLAIN WHERE THE ALLOCATION STEP IS FOUND IN EXHIBIT CDD-2.

A. Pages 16 through 35 of Exhibit CDD-2 contain details on the allocation step of the study, including the allocation of the classified components of rate base on pages 16 through 21. The allocation of each of the classified components of the cost of service to customer classes is shown on pages 22 through 32 of Exhibit CDD-2. The components of the allocated cost of service before revenue credits (shown on page 32, lines 354 through 358) are carried forward to lines 1 through 4 of the Cost of Service Study Summary (pages 1 and 2, Exhibit CDD-2). Pages 33 through 35 of Exhibit CDD-2 provide the customer, demand, and commodity allocation factors applied in the allocation of the rate base (pages 16 through 21) and the cost of service (pages 22 through 32) components.

Q. DID YOU PREPARE SEPARATE CCOS STUDIES FOR THE CTSA AND GCSA?

A. Yes. I prepared separate CCOS studies based on the separate CTSA and GCSA revenue requirements in order to set rates if the Company's request for consolidation is not approved. Exhibit CDD-4 provides the CCOS study for the CTSA, and Exhibit CDD-6 provides the CCOS study for the GCSA based on each area's separate revenue requirement.[6] Each of these studies is presented in the same format as the CGSA CCOS study in Exhibit CDD-2. Thus, my explanation of content of Exhibit CDD-2 applies to Exhibit CDD-4 and to Exhibit CDD-6.

III. CLASS REVENUE ALLOCATION

Q. PLEASE EXPLAIN THE CONCEPT OF CLASS REVENUE ALLOCATION.

A. Class revenue allocation is the assignment of revenue to each customer class so that the total revenue assigned equals the revenue requirement. Upon assignment of revenue to each class, recurring monthly rates must be designed to collect the annual revenue assigned to the class. Conceptually, revenues should be fairly allocated to customer classes and rates should be designed to more accurately capture fixed and variable costs. Equitable class revenue allocations and rate designs are effective in attracting and retaining customers in all classes and keeping their rates reasonable. Interclass inequities that result from residential customers

[6] City of Beaumont customers are included in the GCSA CCOS study.

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 superficially low customer charges with higher usage charges could cause moderate- and high-use customers to consider alternatives to gas service.

Q. HOW ARE THE CCOS STUDY RESULTS USED TO ASSIGN REVENUE TO EACH CLASS?

A. The CGSA CCOS study results that are used for the proposed CGSA class revenue allocation are shown on page 2 of Exhibit CDD-2.[7] 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 CDD-2 combines both the sales and transportation services. 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 CGSA CLASS REVENUE ALLOCATION?

A. The factors I considered in developing my recommendation were class costs and the concept of Gradualism. First, the class revenue allocation must be based on the

[7] With the separate CTSA and GCSA revenue requirements, see page 2 of Exhibits CDD-4 and CDD-6 for the CTSA and GCSA, respectively.

actual CGSA CCOS study results because interclass equity requires that each class pay its own cost of service. If cost-based revenue assignments are not made, a portion of the cost to serve certain classes (those paying less than the cost to serve them) are unfairly borne by other classes (those paying more than the cost of service). Implementing cost-based revenue assignments in this case requires that the proposed CGSA residential revenue increase while each of the non-residential classes are assigned revenue decreases.[8]

However, it is also important to consider the impacts on each customer class that result from cost-based revenue assignments. The concept of gradualism suggests that otherwise-sizable impacts for 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 CTSA and GCSA if the Company's request for consolidation is not approved.

Q. PLEASE EXPLAIN EXHIBIT CDD-3.

A. The three class revenue allocations for the proposed CGSA that I considered are shown on Exhibit CDD-3. Each class' revenue-to-cost ratio and assigned revenue

[8] The CTSA and GCSA CCOS studies based on the separate revenue requirement for each area similarly show that cost-based revenue assignments required substantial residential revenue increases and non-residential revenue decreases in each service area.

change is shown along with the resulting percentage change in non-gas revenue and in total revenue associated with the assigned revenue change.[9]

Q. PLEASE DESCRIBE THE THREE REVENUE ALLOCATIONS CONSIDERED FOR THE PROPOSED CGSA.

A. Revenue Allocation One assigns revenue so that each class pays its actual cost of service. The resulting revenue change for each class is shown on line 5 of Exhibit CDD-3.

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 percent of the cost-based required decrease to the class, with additional adjustments made between the industrial, public authority, and compressed natural gas classes to equalize the revenue to cost ratios between the 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 CDD-3. 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, while ensuring that no other class is assigned revenue that will move it further from a cost-based revenue assignment than it is today. Exhibit CDD-3 shows that this

[9] 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.

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 away from 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 CGSA?

A. Based on the revenue requirement supported by the Company in this SOI, I recommend Revenue Allocation Three for the proposed CGSA. While it is preferable to improve the equity in revenue allocation for all customer classes, i.e., as demonstrated by Revenue Allocation One or Revenue Allocation Two, I recommend Revenue Allocation Three in this case in order to recognize and limit the required residential revenue increase and to reduce the number of litigated issues in this case.[10]

Q. PLEASE EXPLAIN EXHIBITS CDD-5 AND CDD-7.

A. If the Company's request for consolidation is not approved, I have prepared three class revenue allocations for the CTSA and GCSA that are comparable to those developed for the proposed CGSA. The CTSA revenue allocations are shown in Exhibit CDD-5 and the GCSA revenue allocations are shown in Exhibit CDD-7, based on their separate revenue requirements. These two Exhibits are structured in

[10] In making class revenue assignments in GUD No. 10506, the Commission increased the residential revenue assignment with no change for any other class.

the same manner as Exhibit CDD-3. If the proposed service area consolidation is not approved, I recommend Revenue Allocation Three as shown in Exhibits CDD-5 and CDD-7.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

CRYSTAL D. DRUMM (TURNER) – LIST OF PRIOR TESTIMONY

Line	Jurisdiction	Docket	Company	Year
1	Oklahoma Corporation Commission	Cause No. PUD 201500213	Oklahoma Natural Gas	2015
2	Kansas Corporation Commission	Docket No. 16-KGSG-491-RTS	Kansas Gas Service	2016
3	Oklahoma Corporation Commission	Cause No. PUD 201700079	Oklahoma Natural Gas	2017
4	Municipalities of Rio Grande Valley		Texas Gas Service	2017
5	Oklahoma Corporation Commission	Cause No. PUD 201800028	Oklahoma Natural Gas	2018
6	Railroad Commission of Texas	Gas Utilities Docket No. 10766	Texas Gas Service	2018
7	Oklahoma Corporation Commission	Cause No. PUD 201900018	Oklahoma Natural Gas	2019
8	Kansas Corporation Commission	Docket No. 19-EPDE-223-RTS	Kansas Gas Service (Responsive Testimony)	2019

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY SUMMARY

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Customer Costs	$ 100,107,489	$ 94,115,788	$ 5,406,893	$ 42,666	$ 491,970	$ 45,529	$ 4,642
2	Demand Costs	$ 25,170,760	$ 17,551,845	$ 5,126,797	$ 499,815	$ 1,719,945	$ 224,654	$ 47,705
3	Commodity Costs	$ 772,623	$ 416,526	$ 255,340	$ 28,300	$ 61,897	$ 5,225	$ 5,336
4	Cost of Service Before Revenue Credits	$ 126,050,873	$ 112,084,159	$ 10,789,030	$ 570,781	$ 2,273,812	$ 275,408	$ 57,683
5	Revenues Credited to Cost of Service (1)	$ 5,310,492	$ 4,909,627	$ 327,120	$ 13,151	$ 52,938	$ 6,330	$ 1,325
6	Total Cost of Service	$ 120,740,381	$ 107,174,531	$ 10,461,910	$ 557,630	$ 2,220,873	$ 269,078	$ 56,358
7	Revenue at Current Rates	$ 103,693,715	$ 80,613,997	$ 18,406,825	$ 1,224,869	$ 2,965,123	$ 375,105	$ 107,796
8	Revenue Deficiency	$ 17,046,666	$ 26,560,535	$ (7,944,915)	$ (667,238)	$ (744,250)	$ (106,028)	$ (51,438)
9	Revenue-to-Cost Ratios:							
10	Current Revenue	0.8648	0.7630	1.7364	2.1690	1.3273	1.3850	1.8917
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge, special contract, and other revenue are used to offset each class' cost of service. Service charge revenue is directly assigned to classes and is included in the revenue credit on line 5. Allocation of the remaining revenues to be credited is based on each class' cost of service relative to the total cost of service on line 4. The components of the total revenue credit are as follows:

Service Charges	$ 2,415,023
Special Contract	$ 2,872,331
Irrigation	$ 20,483
Unmetered Service	$ 2,655
	$ 5,310,492

STUDY SUMMARY FOR REV. ALLOC.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY SUMMARY FOR REVENUE ALLOCATION

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Customer Costs	$ 100,107,489	$ 94,115,788	$ 5,406,893	$ 42,666	$ 537,499	$ 4,642
2	Demand Costs	$ 25,170,760	$ 17,551,845	$ 5,126,797	$ 499,815	$ 1,944,599	$ 47,705
3	Commodity Costs	$ 772,623	$ 416,526	$ 255,340	$ 28,300	$ 67,122	$ 5,336
4	Cost of Service Before Revenue Credits	$ 126,050,873	$ 112,084,159	$ 10,789,030	$ 570,781	$ 2,549,220	$ 57,683
5	Revenues Credited to Cost of Service	$ 5,310,492	$ 4,909,627	$ 327,120	$ 13,151	$ 59,269	$ 1,325
6	Total Cost of Service	$ 26,044,857	$ 107,174,531	$ 10,461,910	$ 557,630	$ 2,489,951	$ 56,358
7	Revenue at Current Rates	$ 103,693,715	$ 80,613,997	$ 18,406,825	$ 1,224,869	$ 3,340,229	$ 107,796
8	Revenue Deficiency	$ 17,046,666	$ 26,560,535	$ (7,944,915)	$ (667,238)	$ (850,278)	$ (51,438)
9	Revenue-to-Cost Ratios						
10	Current Revenue	0.8648	0.7630	1.7364	2.1690	1.3335	1.8917
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
	Customer and Demand Costs Per Bill		$ 31.65	$ 60.60	$ 775.07	$ 158.01	$ 623.18
	Commodity Cost Per Cff	$ 0.0039					

CLASSIFIED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$ 57,564	$ 43,115	$ 14,360	$ 89
2	302	Franchises and Consents	NONINTPLT	$ 393,474	$ 294,710	$ 98,157	$ 607
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 753,928	$ 564,688	$ 188,077	$ 1,163
4		Total Intangible Plant		$ 1,204,966	$ 902,514	$ 300,594	$ 1,858
5							
6		Transmission Plant					
7	365	Land and Land Rights	DEM	$ 92,083	$ -	$ 92,083	$ -
8	366	Meas. and Reg. Station Structures	DEM	$ 2,346	$ -	$ 2,346	$ -
9	367	Transmission Mains	DEM	$ 12,223,339	$ -	$ 12,223,339	$ -
10	368	Compression Station Equipment	DEM	$ -	$ -	$ -	$ -
11	369	Measuring and Reg. Station Equipment	DEM	$ 2,390,734	$ -	$ 2,390,734	$ -
12	371	Other Equipment	DEM	$ 45,840	$ -	$ 45,840	$ -
13		Total Transmission Plant		$ 14,754,342	$ -	$ 14,754,342	$ -
14							
15		Distribution Plant					
16	374	Land & Land Rights	DIS376-379	$ 5,837,437	$ 3,545,359	$ 2,287,335	$ 4,743
17	375	Structures and Improvements	DIS376-379	$ 60,083	$ 36,491	$ 23,543	$ 49
18	376	Distribution Mains	MAINS	$ 340,592,534	$ 216,872,700	$ 123,719,834	$ -
19	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
20	378	Meas. & Reg. Sta. Equip.- General	DEM	$ 13,797,566	$ -	$ 13,797,566	$ -
21	378	Odorization Tank	COM	$ 693,072	$ -	$ -	$ 693,072
22	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 2,400,890	$ -	$ 2,400,890	$ -
23	379	Odorization Tank	COM	$ 290,146	$ -	$ -	$ 290,146
24	380	Services	CUS	$ 185,624,492	$ 185,624,492	$ -	$ -
25	381	Meters	CUS	$ 65,333,909	$ 65,333,909	$ -	$ -
26	382	Meter Installations	CUS	$ 6,007	$ 6,007	$ -	$ -
27	383	House Regulators	CUS	$ 9,113,503	$ 9,113,503	$ -	$ -
28	385	Meas. & Reg. Sta. Equipment - Industrial	DEM	$ 13,847,802	$ -	$ 13,847,802	$ -

CLASSIFIED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
29	385	Odorization Tank	COM	$ 47,838	$ -	$ -	$ 47,838
30	386	Other Property - Customer Premises	CUS	$ 1,063,249	$ 1,063,249	$ -	$ -
31	387	Other Equipment		$ 0	$ -	$ -	$ -
32		Total Distribution Plant		$ 638,708,527	$ 481,595,709	$ 156,076,970	$ 1,035,847
33							
34		General Plant					
35	389	Land & Land Rights	GENPLT	$ 294,263	$ 282,238	$ 11,945	$ 79
36	390	Structures & Improvements	GENPLT	$ 8,645,712	$ 7,034,679	$ 1,600,412	$ 10,622
37	391	Office Furniture and Equipment	GENPLT	$ 30,337,107	$ 29,607,574	$ 724,724	$ 4,810
38	392	Transportation Equipment	GENPLT	$ 14,770,453	$ 11,137,141	$ 3,609,358	$ 23,954
39	393	Stores Equipment	GENPLT	$ 8,809	$ 6,642	$ 2,153	$ 14
40	394	Tools, Shop & Garage	GENPLT	$ 7,873,507	$ 5,939,036	$ 1,921,717	$ 12,754
41	394	Odorization Tank	COM	$ 14,329	$ -	$ -	$ 14,329
42	396	Major Work Equipment	GENPLT	$ 1,959,844	$ 1,477,752	$ 478,914	$ 3,178
43	397	Communication Equipment	GENPLT	$ 19,159,094	$ 14,572,824	$ 4,556,032	$ 30,237
44	398	Miscellaneous General Plant	GENPLT	$ 130,360	$ 98,293	$ 31,855	$ 211
45		Total General Plant		$ 83,193,478	$ 70,156,179	$ 12,937,109	$ 100,190
46							
47		Total Plant in Service		$ 737,861,313	$ 552,654,402	$ 184,069,015	$ 1,137,896

CLASSIFIED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
48							
49		Depreciation & Amortization Reserve					
50		Intangible Plant	NONINTPLT	$ (1,178,119)	$ (882,405)	$ (293,897)	$ (1,817)
51		Transmission Plant	DEM	$ (3,636,481)	$ -	$ (3,636,481)	$ -
52		Distribution Plant	DISPLTRES	$ (147,644,682)	$ (112,986,265)	$ (34,802,441)	$ 144,024
53		General Plant	GENPLTRES	$ (29,723,482)	$ (24,689,306)	$ (5,001,935)	$ (32,241)
54		Total Depreciation & Amortization Reserve		$ (182,182,765)	$ (138,557,976)	$ (43,734,754)	$ 109,966
55							
56		Net Plant in Service		$ 555,678,548	$ 414,096,426	$ 140,334,261	$ 1,247,862
57							
58		Customer Deposits	CUS	$ (7,853,752)	$ (7,853,752)	$ -	$ -
59							
60		Customer Advances	MAINS/SVCS	$ (21,363,984)	$ (16,341,059)	$ (5,022,925)	$ -
61							
62		Accumulated Deferred Income Taxes	TOTPLT	$ (80,421,556)	$ (60,235,340)	$ (20,062,194)	$ (124,022)
63							
64		Materials and Supplies	TOTPLT	$ 4,272,141	$ 3,199,812	$ 1,065,741	$ 6,588
65							
66		Prepayments	OPEXP	$ 2,581,813	$ 2,160,997	$ 392,121	$ 28,695
67							
68		Pension & FAS 106 Regulatory Asset	OPEXP	$ 25,045,624	$ 20,963,380	$ 3,803,884	$ 278,360
69							
70		DIMP Deferrals	OPEXP	$ 528,827	$ 442,632	$ 80,317	$ 5,877
71							
72		Cash Working Capital	OPEXP	$ (4,999,624)	$ (4,184,724)	$ (759,334)	$ (55,566)
73							
74		Total Rate Base		$ 473,468,036	$ 352,248,372	$ 119,831,871	$ 1,387,793

CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	850-66	Transmission Expenses	DEM	$ 972,153	$ -	$ 972,153	$ -
3	870	Operation Supervision & Engineering	DIS871-879	$ 735,005	$ 600,373	$ 114,286	$ 20,346
4	870	Odorization	COM	$ 814	$ -	$ -	$ 814
5	871	Distribution Load Dispatch	COM	$ 260,199	$ -	$ -	$ 260,199
6	874	Mains and Services Expenses	MAINS/SVCS	$ 4,244,625	$ 3,246,664	$ 997,962	$ -
7	874	Odorization	COM	$ 964	$ -	$ -	$ 964
8	875	Measuring & Reg. Station Expense - General	DEM	$ 391,310	$ -	$ 391,310	$ -
9	875	Odorization	COM	$ 58,361	$ -	$ -	$ 58,361
10	876	Meas. & Reg. Station Expense.- Industrial	DEM	$ 68,073	$ -	$ 68,073	$ -
11	877	Meas. & Regulating Station Exp.- City Gate	DEM	$ 4,260	$ -	$ 4,260	$ -
12	878	Meter and House Regulator Expenses	CUS	$ 4,347,173	$ 4,347,173	$ -	$ -
13	879	Customer Installation Expenses	CUS	$ 84,335	$ 84,335	$ -	$ -
14	880	Other Expenses	CUS	$ 1,446,075	$ 1,446,075	$ -	$ -
15	880	Odorization	COM	$ 51	$ -	$ -	$ 51
16	881	Rents	DIS871-879	$ (188,295)	$ (153,805)	$ (29,278)	$ (5,212)
17		Total Transmission & Distribution Oper. Exp.		$ 12,425,104	$ 9,570,816	$ 2,518,766	$ 335,522
18							
19		Distribution Maintenance Expenses					
20	885	Maintenance Supervision and Engineering	DIS887-893	$ 72	$ 41	$ 31	$ -
21	886	Structures and Improvements	DIS887-893	$ 362,515	$ 204,641	$ 157,874	$ -
22	887	Maintenance of Mains	MAINS	$ 3,313,703	$ 2,110,004	$ 1,203,699	$ -
23	889	Maint. of Meas. & Reg. Sta. Equip.- General	DEM	$ 395,845	$ -	$ 395,845	$ -
24	889	Odorization	COM	$ 17,985	$ -	$ -	$ 17,985

CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
25	890	Maint. of Meas. & Reg. Sta. Equip. - Industrial	DEM	$ 585,505	$ -	$ 585,505	$ -
26	891	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 19,823	$ -	$ 19,823	$ -
27	892	Maintenance of Services	CUS	$ 740,925	$ 740,925	$ -	$ -
28	893	Main. of Meters & House Regulators	CUS	$ 7,092	$ 7,092	$ -	$ -
29	894	Maintenance of Other Equipment	DIS887-893	$ -	$ -	$ -	$ -
30		Total Distribution Maintenance Expenses		$ 5,443,464	$ 3,062,703	$ 2,362,777	$ 17,985
31							
32		Total Operations & Maintenance Expenses		$ 17,868,568	$ 12,633,519	$ 4,881,542	$ 353,507
33							
34		Customer Accounts Expenses					
35	901	Supervision	CUS	$ 154,499	$ 154,499	$ -	$ -
36	902	Meter Reading Expense	CUS	$ 1,351,191	$ 1,351,191	$ -	$ -
37	903	Customer Accounting	CUS	$ 4,115,966	$ 4,115,966	$ -	$ -
38	904	Bad Debts (includes gross up)	CUS	$ 677,271	$ 677,271	$ -	$ -
39	905	Miscellaneous Customer Accounts Expenses	CUS	$ 342,471	$ 342,471	$ -	$ -
40		Total Customer Accounts Expenses		$ 6,641,399	$ 6,641,399	$ -	$ -
41							
42		Customer Service Expenses					
43	907	Supervision	CUS	$ -	$ -	$ -	$ -
44	908	Customer Assistance	CUS	$ 743,891	$ 743,891	$ -	$ -
45	909	Informational and Instructional Advertising	CUS	$ 93,297	$ 93,297	$ -	$ -
46		Total Customer Service Expenses		$ 837,188	$ 837,188	$ -	$ -
47							
48		Sales and Advertising Expenses					

CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
49	912	Demonstrating and Selling	CUS	$ -	$ -	$ -	$ -
50	913	Advertising	CUS	$ 23,611	$ 23,611	$ -	$ -
51		Total Sales and Advertising Expenses		$ 23,611	$ 23,611	$ -	$ -
52							
53		<u>Administrative & General Expenses</u>					
54	921-32	Administrative & General Expenses	ADMINGEN	$ 26,311,246	$ 23,122,526	$ 2,967,828	$ 220,893
55		Total Administrative & General Expenses		$ 26,311,246	$ 23,122,526	$ 2,967,828	$ 220,893
56							
57		<u>Depreciation and Amortization Expense</u>					
58	301-303	Intangible Plant	PLT301-03	$ 32,365	$ 24,241	$ 8,074	$ 50
59	365	Land and Land Rights	DEM	$ 32	$ -	$ 32	$ -
60	366	Meas. and Reg. Station Structures	PLT366	$ 95	$ -	$ 95	$ -
61	367	Transmission Mains	PLT367	$ 213,908	$ -	$ 213,908	$ -
62	368	Compression Station Equipment	PLT368	$ -	$ -	$ -	$ -
63	369	Measuring and Reg. Station Equipment	PLT369	$ 50,155	$ -	$ 50,155	$ -
64	371	Other Equipment	PLT371	$ 1,201	$ -	$ 1,201	$ -
65	375	Structures and Improvements	PLT375	$ 1,136	$ 690	$ 445	$ 1
66	376	Mains	PLT376	$ 7,674,509	$ 4,886,752	$ 2,787,756	$ -
67	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
68	378	Meas. & Reg. Sta. Equipment - General	PLT378	$ 296,057	$ -	$ 296,057	$ -
69	378	Odorization Tank	COM	$ 14,693	$ -	$ -	$ 14,693
70	379	Meas. & Reg. Sta. Equipment - City Gate	PLT379	$ 40,742	$ -	$ 40,742	$ -
71	379	Odorization Tank	COM	$ 4,903	$ -	$ -	$ 4,903
72	380	Services	PLT380	$ 4,742,152	$ 4,742,152	$ -	$ -

CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
73	381	Meters	PLT381	$ 2,639,514	$ 2,639,514	$ -	$ -
74	382	Meter Installations	PLT382	$ -	$ -	$ -	$ -
75	383	House Regulators	PLT383	$ 232,452	$ 232,452	$ -	$ -
76	385	Meas. & Reg. Sta. Equip. - Industrial	PLT385	$ 297,860	$ -	$ 297,860	$ -
77	385	Odorization Tank	COM	$ 1,029	$ -	$ -	$ 1,029
78	386	Other Property - Customer Premises	PLT386	$ (1,701)	$ (1,701)	$ -	$ -
79	387	Other Equipment		$ 0	$ -	$ -	$ -
80	389-98	General Plant	GENDEP	$ 5,110,034	$ 4,509,586	$ 595,539	$ 4,909
81	4073	Pension & FAS 106 Amortization Expense	OPEXP	$ 330,846	$ 276,921	$ 50,248	$ 3,677
82		Total Depreciation and Amortization Expense		$ 21,681,983	$ 17,310,608	$ 4,342,113	$ 29,262
83							
84		Taxes Other Than Income					
85	408	Payroll and Other	OPEXP	$ 2,624,541	$ 2,196,761	$ 398,610	$ 29,169
86	408	Ad Valorem	TOTPLT	$ 4,385,203	$ 3,284,495	$ 1,093,945	$ 6,763
87	408	Revenue Related (includes gross up)	CUS	$ 141,127	$ 141,127	$ -	$ -
88		Total Taxes Other Than Income		$ 7,150,871	$ 5,622,382.69	$ 1,492,555.87	$ 35,932.08
89							
90	431	Interest on Customer Deposits	CUS	$ 150,792	$ 150,792	$ -	$ -
91							
92		Required Return	RB	$ 37,529,690	$ 27,921,150	$ 9,498,536	$ 110,004
93		Income Taxes	RB	$ 7,855,526	$ 5,844,315	$ 1,988,186	$ 23,026
94		Total Cost of Service Before Revenue Credits		$ 126,050,873	$ 100,107,489	$ 25,170,760	$ 772,623

CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**CUS**	**Customer Factor**		**1.00000**	**0.00000**	**0.00000**
2							
3		**DEM**	**Demand Factor**		**0.00000**	**1.00000**	**0.00000**
4							
5		**COM**	**Commodity Factor**		**0.00000**	**0.00000**	**1.00000**
6							
7		**DEM-COM**	**Demand and Commodity Factor**		**0.00000**	**0.50000**	**0.50000**
8							
9			Total Transmission Plant	$ 14,754,342	$ -	$ 14,754,342	$ -
10			Total Distribution Plant	$ 638,708,527	$ 481,595,709	$ 156,076,970	$ 1,035,847
11			Total General Plant	$ 83,193,478	$ 70,156,179	$ 12,937,109	$ 100,190
12			Total Non-Intangible Plant	$ 736,656,347	$ 551,751,889	$ 183,768,421	$ 1,136,037
13		**NONINTPLT**	**Non-Intangible Plant Factor**	**1.00000**	**0.74899**	**0.24946**	**0.00154**
14							
15	376		Distribution Mains	$ 340,592,534	$ 216,872,700	$ 123,719,834	$ -
16	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
17	378		Meas. & Reg. Sta. Equip.- General	$ 13,797,566	$ -	$ 13,797,566	$ -
18	379		Meas. & Reg. Sta. Equip.- City Gate	$ 2,691,036	$ -	$ 2,400,890	$ 290,146
19			Total Accounts 376-379	$ 357,081,136	$ 216,872,700	$ 139,918,290	290,146
20		**DIS376-379**	**Accounts 376-379 Factor**	**1.00000**	**0.60735**	**0.39184**	**0.00081**
21							
22	376		Mains	$ 340,592,534	$ 216,872,700	$ 123,719,834	$ -
23		**MAINS**	**Distribution Mains Factor**	**1.00000**	**0.63675**	**0.36325**	**0.00000**
24							
25	376/380		Mains and Services	$ 526,217,025	$ 402,497,192	$ 123,719,834	$ -
26		**MAINS/SVCS**	**Mains and Services Factor**	**1.00000**	**0.76489**	**0.23511**	**0.00000**

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CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
27							
28	374-87		Total Distribution Plant	$ 638,708,527	$ 481,595,709	$ 156,076,970	$ 1,035,847
29		**DISPLT**	**Distribution Plant Factor**	**1.00000**	**0.75401**	**0.24436**	**0.00162**
30							
31			General Plant Reserve	$ (29,723,482)	$ (24,689,306)	$ (5,001,935)	$ (32,241)
32		**GENPLTRES**	**General Plant Reserve Factor**	**1.00000**	**0.83063**	**0.16828**	**0.00108**
33							
34			Total Plant	$ 737,861,313	$ 552,654,402	$ 184,069,015	$ 1,137,896
35		**TOTPLT**	**Total Plant Factor**	**1.00000**	**0.74899**	**0.24946**	**0.00154**
36							
37	374		Land & Land Rights	$ (9,695)	$ (5,888)	$ (3,799)	$ (8)
38	375		Structures and Improvements	$ 4,229	$ 2,569	$ 1,657	$ 3
39	376		Distribution Mains	$ (72,946,895)	$ (46,449,022)	$ (26,497,873)	$ -
40	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
41	378		Meas. & Reg. Station Equip.- General	$ (2,833,020)	$ -	$ (2,833,020)	$ -
42	378		Odorization Tank	$ 104,970	$ -	$ -	$ 104,970
43	379		Meas. & Reg. Station Equip.- City Gate	$ (735,409)	$ -	$ (735,409)	$ -
44	379		Odorization Tank	$ 39,916	$ -	$ -	$ 39,916
45	380		Services	$ (37,018,022)	$ (37,018,022)	$ -	$ -
46	381		Meters	$ (24,888,362)	$ (24,888,362)	$ -	$ -
47	382		Meter Installations	$ (10,203)	$ (10,203)	$ -	$ -
48	383		House Regulators	$ (3,976,993)	$ (3,976,993)	$ -	$ -
49	385		Meas. & Reg. Sta. Equipment - Industrial	$ (4,320,871)	$ -	$ (4,320,871)	$ -
50	386		Other Property - Customer Premises	$ (1,054,327)	$ (640,344)	$ (413,126)	$ (857)
51	387		Other Equipment	$ -			
52			Total Distribution Plant Reserve	$ (147,644,682)	$ (112,986,265)	$ (34,802,441)	$ 144,024

CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
53		**DISPLTRES**	**Distribution Plant Reserve**	**1.00000**	**0.76526**	**0.23572**	**(0.00098)**
54							
55			Total Operations and Maintenance Expenses	$ 17,868,568	$ 12,633,519	$ 4,881,542	$ 353,507
56			Total Customer Accounts Expenses	$ 6,641,399	$ 6,641,399	$ -	$ -
57			Total Customer Service Expenses	$ 837,188	$ 837,188	$ -	$ -
58			Total Sales and Advertising Expenses	$ 23,611	$ 23,611	$ -	$ -
59			Administrative and General Expenses	$ 26,311,246	$ 23,122,526	$ 2,967,828	$ 220,893
60			Total Operating Expenses	$ 51,682,012	$ 43,258,242	$ 7,849,370	$ 574,399
61		**OPEXP**	**Operating Expense Factor**	**1.00000**	**0.83701**	**0.15188**	**0.01111**
62							
63	871		Distribution Load Dispatch	$ 260,199	$ -	$ -	$ 260,199
64	874		Mains and Services Expenses	$ 4,244,625	$ 3,246,664	$ 997,962	$ -
65	875		Measuring & Reg. Station Expense - General	$ 391,310	$ -	$ 391,310	$ -
66	876		Meas. & Reg. Station Expense.- Industrial	$ 68,073	$ -	$ 68,073	$ -
67	877		Meas. & Regulating Station Exp.- City Gate	$ 4,260	$ -	$ 4,260	$ -
68	878		Meter and House Regulator Expenses	$ 4,347,173	$ 4,347,173	$ -	$ -
69	879		Customer Installation Expenses	$ 84,335	$ 84,335	$ -	$ -
70			Total Accounts 871-879	$ 9,399,975	$ 7,678,172	$ 1,461,604	$ 260,199
71		**DIS871-879**	**Accounts 871-879 Factor**	**1.00000**	**0.81683**	**0.15549**	**0.02768**
72							
73	887		Maintenance of Mains	$ 3,313,703	$ 2,110,004	$ 1,203,699	$ -
74	889		Maint. of Meas. & Reg. Sta. Equip.- General	$ 395,845	$ -	$ 395,845	$ -
75	890		Maint. of Meas. & Reg. Sta. Equip. - Industrial	$ 585,505	$ -	$ 585,505	$ -
76	891		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 19,823	$ -	$ 19,823	$ -
77	892		Maintenance of Services	$ 740,925	$ 740,925	$ -	$ -
78	893		Main. of Meters & House Regulators	$ 7,092	$ 7,092	$ -	$ -

CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
79			Total Accounts 887-893	$ 5,062,892	$ 2,858,021	$ 2,204,871	$ -
80		**DIS887-893**	**Accounts 887-893 Factor**	**1.00000**	**0.56450**	**0.43550**	**0.00000**
81							
82			Total Operations and Maintenance Expenses	$ 17,868,568	$ 12,633,519	$ 4,881,542	$ 353,507
83			Total Customer Accounts Expenses	$ 6,641,399	$ 6,641,399	$ -	-
84			Total Customer Service Expenses	$ 837,188	$ 837,188	$ -	-
85			Total Sales and Advertising Expenses	$ 23,611	$ 23,611	$ -	$ -
86			Total Operating Exp. Without A&G Expenses	$ 25,370,766	$ 20,135,717	$ 4,881,542	$ 353,507
87		**NONAGOPEXP**	**Non-A&G Operating Expenses Factor**	**1.00000**	**0.79366**	**0.19241**	**0.01393**
88							
89	920-932		Administrative and General Expenses	$ 26,311,246	$ 23,122,526	$ 2,967,828	$ 220,893
90		**ADMINGEN**	**Administrative and General Expenses Factor**	**1.00000**	**0.87881**	**0.11280**	**0.00840**
91							
92	366		Meas. and Reg. Station Structures	$ 2,346	$ -	$ 2,346	$ -
93		**PLT366**	**Measuring and Reg. Station Structures Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
94							
95	367		Transmission Mains	$ 12,223,339	$ -	$ 12,223,339	$ -
96		**PLT367**	**Transmission Mains**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
97							
98	368		Compression Station Equipment	$ -	$ -	$ -	$ -
99		**PLT368**	**Compression Station Equipment Factor**	**0.00000**	**0.00000**	**0.00000**	**0.00000**
100							
101	369		Measuring and Reg. Station Equipment	$ 2,390,734	$ -	$ 2,390,734	$ -
102		**PLT369**	**Measuring & Reg, Station Equipment Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
103							
104	371		Other Equipment	$ 45,840	$ -	$ 45,840	$ -

CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
105		**PLT371**	**Other Equipment Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
106							
107	375		Structures and Improvements	$ 60,083	$ 36,491	$ 23,543	$ 49
108		**PLT375**	**Structures and Improvements Factor**	**1.00000**	**0.60735**	**0.39184**	**0.00081**
109							
110	376		Distribution Mains	$ 340,592,534	$ 216,872,700	$ 123,719,834	$ -
111		**PLT376**	**Distribution Mains Factor**	**1.00000**	**0.63675**	**0.36325**	**0.00000**
112							
113	378		Meas. & Reg. Sta. Equip.- General	$ 13,797,566	$ -	$ 13,797,566	$ -
114		**PLT378**	**Meas. & Reg. Station Equip. - General Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
115							
116	379		Meas. & Reg. Sta. Equip.- City Gate	$ 2,400,890	$ -	$ 2,400,890	$ -
117		**PLT379**	**Meas. & Reg. Station Equip. - City Gate Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
118							
119	380		Services	$ 185,624,492	$ 185,624,492	$ -	$ -
120		**PLT380**	**Services Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
121							
122	381		Meters	$ 65,333,909	$ 65,333,909	$ -	$ -
123		**PLT381**	**Meters Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
124							
125	382		Meter Installations	$ 6,007	$ 6,007	$ -	$ -
126		**PLT382**	**Meter Installations Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
127							
128	383		House Regulators	$ 9,113,503	$ 9,113,503	$ -	$ -
129		**PLT383**	**House Regulators Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
130							

CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
131	385		Meas. & Reg. Sta. Equipment - Industrial	$ 13,847,802	$ -	$ 13,847,802	$ -
132		**PLT385**	**Meas. & Reg. Sta. Equip.-Industrial Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
133							
134	386		Other Property - Customer Premises	$ 1,063,249	$ 1,063,249	$ -	$ -
135		**PLT386**	**Other Property-Customer Premises Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
136							
137	301-03		Intangible Plant	$ 1,204,966	$ 902,514	$ 300,594	$ 1,858
138		**PLT301-03**	**Intangible Plant**	**1.00000**	**0.74899**	**0.24946**	**0.00154**
139							
140	389-98		General Plant Depreciation Expense	$ 5,110,034	$ 4,509,586	$ 595,539	$ 4,909
141		**GENDEP**	**General Plant Depreciation Expense Factor**	**1.00000**	**0.88250**	**0.11654**	**0.00096**
142							
143			Rate Base	$ 473,468,036	$ 352,248,372	$ 119,831,871	$ 1,387,793
144		**RB**	**Rate Base Factor**	**1.00000**	**0.74397**	**0.25309**	**0.00293**

ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	301-303	**Intangible Plant**								
2		Customer	CUS	$ 902,514	$ 856,319	$ 42,191	$ 170	$ 3,559	$ 254	$ 20
3		Demand	DEM	$ 300,594	$ 222,215	$ 52,742	$ 5,142	$ 17,694	$ 2,311	$ 491
4		Commodity	COM	$ 1,858	$ 1,002	$ 614	$ 68	$ 149	$ 13	$ 13
		Total Intangible Plant		$ 1,204,966	$ 1,079,536	$ 95,547	$ 5,380	$ 21,402	$ 2,577	$ 524
5	365-371	**Transmission Plant**								
6		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7		Demand	DEM	$ 14,754,342	$ 10,907,177	$ 2,588,772	$ 252,381	$ 868,485	$ 113,439	$ 24,088
8		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Total Transmission Plant		$ 14,754,342	$ 10,907,177	$ 2,588,772	$ 252,381	$ 868,485	$ 113,439	$ 24,088
10		**Distribution Plant**								
11	374	**Land & Land Rights**								
12		Customer	CUS	$ 3,545,359	$ 3,363,893	$ 165,741	$ 667	$ 13,982	$ 996	$ 80
13		Demand	DEM	$ 2,287,335	$ 1,690,917	$ 401,332	$ 39,126	$ 134,639	$ 17,586	$ 3,734
14		Commodity	COM	$ 4,743	$ 2,557	$ 1,568	$ 174	$ 380	$ 32	$ 33
15		Total Land & Land Rights		$ 5,837,437	$ 5,057,367	$ 568,640	$ 39,967	$ 149,001	$ 18,614	$ 3,847
16	375	**Structures and Improvements**								
17		Customer	CUS	$ 36,491	$ 34,623	$ 1,706	$ 7	$ 144	$ 10	$ 1
18		Demand	DEM	$ 23,543	$ 17,404	$ 4,131	$ 403	$ 1,386	$ 181	$ 38
19		Commodity	COM	$ 49	$ 26	$ 16	$ 2	$ 4	$ 0	$ 0
20		Total Structures and Improvements		$ 60,083	$ 52,054	$ 5,853	$ 411	$ 1,534	$ 192	$ 40
21	376	**Distribution Mains**								
22		Customer	CUS	$ 216,872,700	$ 205,772,242	$ 10,138,517	$ 40,823	$ 855,288	$ 60,931	$ 4,899
23		Demand	DEM	$ 123,719,834	$ 91,460,140	$ 21,707,672	$ 2,116,294	$ 7,282,518	$ 951,220	$ 201,989
24		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Total Distribution Mains		$ 340,592,534	$ 297,232,382	$ 31,846,189	$ 2,157,117	$ 8,137,806	$ 1,012,151	$ 206,889
26	377	**Compressor Station Equipment**								
27		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	378	**Meas. & Reg. Sta. Equip. - General**								
32		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33		Demand	DEM	$ 13,797,566	$ 10,199,879	$ 2,420,898	$ 236,015	$ 812,166	$ 106,083	$ 22,526

Exhibit CDD-2
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ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
34		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35		Total Meas. & Reg. Sta. Equip.- Gen.		$ 13,797,566	$ 10,199,879	$ 2,420,898	$ 236,015	$ 812,166	$ 106,083	$ 22,526
36	378	**Odorization Tank**								
37		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Commodity	COM	$ 693,072	$ 373,639	$ 229,049	$ 25,386	$ 55,524	$ 4,687	$ 4,786
40		Total Odorization Tank		$ 693,072	$ 373,639	$ 229,049	$ 25,386	$ 55,524	$ 4,687	$ 4,786
41	379	**Meas. & Reg. Station - City Gate**								
42		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43		Demand	DEM	$ 2,400,890	$ 1,774,863	$ 421,256	$ 41,069	$ 141,324	$ 18,459	$ 3,920
44		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45		Total Meas. & Reg. Equip.-City Gate		$ 2,400,890	$ 1,774,863	$ 421,256	$ 41,069	$ 141,324	$ 18,459	$ 3,920
46	379	**Odorization Tank**								
47		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49		Commodity	COM	$ 290,146	$ 156,419	$ 95,888	$ 10,628	$ 23,244	$ 1,962	$ 2,004
50		Total Odorization Tank		$ 290,146	$ 156,419	$ 95,888	$ 10,628	$ 23,244	$ 1,962	$ 2,004
51	380	**Services**								
52		Customer	SERCUS	$ 185,624,492	$ 175,065,817	$ 9,554,338	$ 49,774	$ 877,158	$ 72,095	$ 5,312
53		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Total Services		$ 185,624,492	$ 175,065,817	$ 9,554,338	$ 49,774	$ 877,158	$ 72,095	$ 5,312
56	381	**Meters**								
57		Customer	METCUS	$ 65,333,909	$ 59,082,872	$ 5,449,115	$ 87,355	$ 624,774	$ 79,787	$ 10,006
58		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Total Meters		$ 65,333,909	$ 59,082,872	$ 5,449,115	$ 87,355	$ 624,774	$ 79,787	$ 10,006
61	382	**Meter Installations**								
62		Customer	METCUS	$ 6,007	$ 5,433	$ 501	$ 8	$ 57	$ 7	$ 1
63		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65		Total Meter Installations		$ 6,007	$ 5,433	$ 501	$ 8	$ 57	$ 7	$ 1
66	383	**House Regulators**								
67		Customer	REGCUS	$ 9,113,503	$ 7,946,452	$ 1,011,336	$ 16,780	$ 120,383	$ 16,669	$ 1,882

ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
68		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70		Total House Regulators		$ 9,113,503	$ 7,946,452	$ 1,011,336	$ 16,780	$ 120,383	$ 16,669	$ 1,882
71	385	**Meas. & Reg. Sta. Equipment - Industrial**								
72		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73		Demand	NRDEM	$ 13,847,802	$ -	$ 9,318,239	$ 908,441	$ 3,126,095	$ 408,321	$ 86,706
74		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75		Total Meas. & Reg. Sta. Equip.- Ind.		$ 13,847,802	$ -	$ 9,318,239	$ 908,441	$ 3,126,095	$ 408,321	$ 86,706
76	385	**Odorization Tank**								
77		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79		Commodity	COM	$ 47,838	$ 25,790	$ 15,810	$ 1,752	$ 3,832	$ 324	$ 330
80		Total Odorization Tank		$ 47,838	$ 25,790	$ 15,810	$ 1,752	$ 3,832	$ 324	$ 330
81	386	**Other Prop.-Customer Premises**								
82		Customer	CUS	$ 1,063,249	$ 1,008,828	$ 49,706	$ 200	$ 4,193	$ 299	$ 24
83		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85		Total Other Prop.- Cust. Premises		$ 1,063,249	$ 1,008,828	$ 49,706	$ 200	$ 4,193	$ 299	$ 24
86	387	**Other Equipment**								
87		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
91		**Total Distribution Plant**								
92		Customer		$ 481,595,709	$ 452,280,159	$ 26,370,959	$ 195,614	$ 2,495,979	$ 230,794	$ 22,204
93		Demand		$ 156,076,970	$ 105,143,204	$ 34,273,527	$ 3,341,347	$ 11,498,128	$ 1,501,850	$ 318,914
94		Commodity		$ 1,035,847	$ 558,431	$ 342,331	$ 37,942	$ 82,985	$ 7,006	$ 7,153
95		Total Distribution Plant		$ 638,708,527	$ 557,981,793	$ 60,986,817	$ 3,574,903	$ 14,077,092	$ 1,739,650	$ 348,272
96		**Total General Plant**								
97		Customer	CUS	$ 70,156,179	$ 66,565,291	$ 3,279,710	$ 13,206	$ 276,677	$ 19,710	$ 1,585
98		Demand	DEM	$ 12,937,109	$ 9,563,784	$ 2,269,923	$ 221,296	$ 761,517	$ 99,467	$ 21,122
99		Commodity	COM	$ 100,190	$ 54,013	$ 33,111	$ 3,670	$ 8,026	$ 678	$ 692
100		Total General Plant		$ 83,193,478	$ 76,183,088	$ 5,582,745	$ 238,172	$ 1,046,220	$ 119,855	$ 23,398
101		**Total Plant in Service**								

ALLOCATED RATE BASE

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CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
102		Customer		$ 552,654,402	$ 519,701,768	$ 29,692,861	$ 208,990	$ 2,776,215	$ 250,758	$ 23,810
103		Demand		$ 184,069,015	$ 125,836,381	$ 39,184,963	$ 3,820,166	$ 13,145,823	$ 1,717,067	$ 364,615
104		Commodity		$ 1,137,896	$ 613,446	$ 376,056	$ 41,680	$ 91,160	$ 7,696	$ 7,858
105		Total Plant in Service		$ 737,861,313	$ 646,151,595	$ 69,253,881	$ 4,070,835	$ 16,013,199	$ 1,975,521	$ 396,283
106		**Depreciation & Amort. Reserve**								
107		**Intangible Plant**								
108		Customer	CUS	$ (882,405)	$ (837,240)	$ (41,251)	$ (166)	$ (3,480)	$ (248)	$ (20)
109		Demand	DEM	$ (293,897)	$ (217,264)	$ (51,567)	$ (5,027)	$ (17,300)	$ (2,260)	$ (480)
110		Commodity	COM	$ (1,817)	$ (979)	$ (600)	$ (67)	$ (146)	$ (12)	$ (13)
111		Total Intangible Plant		$ (1,178,119)	$ (1,055,483)	$ (93,418)	$ (5,260)	$ (20,925)	$ (2,520)	$ (512)
112		**Transmission Plant**								
113		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
114		Demand	DEM	$ (3,636,481)	$ (2,688,276)	$ (638,051)	$ (62,204)	$ (214,054)	$ (27,959)	$ (5,937)
115		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116		Total Transmission Plant		$ (3,636,481)	$ (2,688,276)	$ (638,051)	$ (62,204)	$ (214,054)	$ (27,959)	$ (5,937)
117		**Distribution Plant**								
118		Customer	DISPLTCUS	$ (112,986,265)	$ (106,108,599)	$ (6,186,841)	$ (45,893)	$ (585,577)	$ (54,146)	$ (5,209)
119		Demand	DISPLTDEM	$ (34,802,441)	$ (23,445,100)	$ (7,642,399)	$ (745,062)	$ (2,563,882)	$ (334,886)	$ (71,112)
120		Commodity	COM	$ 144,024	$ 77,644	$ 47,598	$ 5,275	$ 11,538	$ 974	$ 995
121		Total Distribution Plant		$ (147,644,682)	$ (129,476,055)	$ (13,781,642)	$ (785,679)	$ (3,137,921)	$ (388,058)	$ (75,327)
122		**General Plant**								
123		Customer	CUS	$ (24,689,306)	$ (23,425,603)	$ (1,154,193)	$ (4,647)	$ (97,368)	$ (6,936)	$ (558)
124		Demand	DEM	$ (5,001,935)	$ (3,697,691)	$ (877,631)	$ (85,561)	$ (294,429)	$ (38,457)	$ (8,166)
125		Commodity	COM	$ (32,241)	$ (17,382)	$ (10,655)	$ (1,181)	$ (2,583)	$ (218)	$ (223)
126		Total General Plant		$ (29,723,482)	$ (27,140,676)	$ (2,042,479)	$ (91,389)	$ (394,380)	$ (45,612)	$ (8,947)
127		**Total Depr. & Amort. Reserve**								
128		Customer		$ (138,557,976)	$ (130,371,442)	$ (7,382,286)	$ (50,706)	$ (686,425)	$ (61,330)	$ (5,787)
129		Demand		$ (43,734,754)	$ (30,048,331)	$ (9,209,647)	$ (897,854)	$ (3,089,665)	$ (403,563)	$ (85,696)
130		Commodity		$ 109,966	$ 59,283	$ 36,342	$ 4,028	$ 8,810	$ 744	$ 759
131		Total Depr. & Amortization Reserve		$ (182,182,765)	$ (160,360,490)	$ (16,555,591)	$ (944,532)	$ (3,767,280)	$ (464,149)	$ (90,723)
132		**Net Plant in Service**								
133		Customer		$ 414,096,426	$ 389,330,326	$ 22,310,575	$ 158,284	$ 2,089,791	$ 189,427	$ 18,023
134		Demand		$ 140,334,261	$ 95,788,050	$ 29,975,316	$ 2,922,312	$ 10,056,159	$ 1,313,505	$ 278,920
135		Commodity		$ 1,247,862	$ 672,729	$ 412,398	$ 45,708	$ 99,970	$ 8,440	$ 8,618

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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
136		Total Net Plant in Service		$ 555,678,548	$ 485,791,105	$ 52,698,290	$ 3,126,303	$ 12,245,919	$ 1,511,371	$ 305,560
137		**Customer Deposits**								
138		Customer	DEPCUS	$ (7,853,752)	$ (4,634,440)	$ (3,175,747)	$ (35,306)	$ (7,435)	$ (824)	$ -
139		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
140		Commodity	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
141		Total Customer Deposits		$ (7,853,752)	$ (4,634,440)	$ (3,175,747)	$ (35,306)	$ (7,435)	$ (824)	$ -
142		**Customer Advances**								
143		Customer	MSCUS	$ (16,341,059)	$ (15,461,716)	$ (799,514)	$ (3,678)	$ (70,336)	$ (5,401)	$ (415)
144		Demand	DEM	$ (5,022,925)	$ (3,713,207)	$ (881,314)	$ (85,920)	$ (295,664)	$ (38,619)	$ (8,201)
145		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
146		Total Customer Advances		$ (21,363,984)	$ (19,174,923)	$ (1,680,828)	$ (89,598)	$ (366,000)	$ (44,019)	$ (8,615)
147		**Accum. Deferred Income Taxes**								
148		Customer	TPLTCUS	$ (60,235,340)	$ (56,643,741)	$ (3,236,307)	$ (22,778)	$ (302,587)	$ (27,331)	$ (2,595)
149		Demand	TPLTDEM	$ (20,062,194)	$ (13,715,257)	$ (4,270,878)	$ (416,370)	$ (1,432,800)	$ (187,148)	$ (39,740)
150		Commodity	COM	$ (124,022)	$ (66,861)	$ (40,987)	$ (4,543)	$ (9,936)	$ (839)	$ (856)
151		Total Accum. Deferred Inc. Taxes		$ (80,421,556)	$ (70,425,859)	$ (7,548,173)	$ (443,692)	$ (1,745,323)	$ (215,317)	$ (43,192)
152		**Materials and Supplies**								
153		Customer	TPLTCUS	$ 3,199,812	$ 3,009,020	$ 171,919	$ 1,210	$ 16,074	$ 1,452	$ 138
154		Demand	TPLTDEM	$ 1,065,741	$ 728,580	$ 226,877	$ 22,118	$ 76,113	$ 9,942	$ 2,111
155		Commodity	COM	$ 6,588	$ 3,552	$ 2,177	$ 241	$ 528	$ 45	$ 45
156		Total Materials and Supplies		$ 4,272,141	$ 3,741,151	$ 400,973	$ 23,570	$ 92,715	$ 11,438	$ 2,294
157		**Prepayments**								
158		Customer	OPEXPCUS	$ 2,160,997	$ 2,023,400	$ 123,346	$ 1,163	$ 11,764	$ 1,197	$ 128
159		Demand	OPEXPDEM	$ 392,121	$ 256,997	$ 90,926	$ 8,864	$ 30,504	$ 3,984	$ 846
160		Commodity	COM	$ 28,695	$ 15,469	$ 9,483	$ 1,051	$ 2,299	$ 194	$ 198
161		Total Prepayments		$ 2,581,813	$ 2,295,866	$ 223,754	$ 11,079	$ 44,567	$ 5,375	$ 1,172
162		**Pension & FAS 106 Reg. Asset**								
163		Customer	OPEXPCUS	$ 20,963,380	$ 19,628,575	$ 1,196,549	$ 11,284	$ 114,122	$ 11,608	$ 1,242
164		Demand	OPEXPDEM	$ 3,803,884	$ 2,493,070	$ 882,052	$ 85,992	$ 295,912	$ 38,651	$ 8,207
165		Commodity	COM	$ 278,360	$ 150,065	$ 91,993	$ 10,196	$ 22,300	$ 1,883	$ 1,922
166		Total Pen. & FAS 106 Reg. Asset		$ 25,045,624	$ 22,271,710	$ 2,170,595	$ 107,472	$ 432,334	$ 52,142	$ 11,372
167		**DIMP Deferrals**								
168		Customer	TPLTCUS	$ 442,632	$ 416,240	$ 23,782	$ 167	$ 2,224	$ 201	$ 19
169		Demand	TPLTDEM	$ 80,317	$ 54,908	$ 17,098	$ 1,667	$ 5,736	$ 749	$ 159

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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
170		Commodity	COM	$ 5,877	$ 3,169	$ 1,942	$ 215	$ 471	$ 40	$ 41
171		Total DIMP Deferrals		$ 528,827	$ 474,316	$ 42,822	$ 2,050	$ 8,430	$ 990	$ 219
172		**Cash Working Capital**								
173		Customer	OPEXPCUS	$ (4,184,724)	$ (3,918,269)	$ (238,856)	$ (2,253)	$ (22,781)	$ (2,317)	$ (248)
174		Demand	OPEXPDEM	$ (759,334)	$ (497,668)	$ (176,076)	$ (17,166)	$ (59,070)	$ (7,716)	$ (1,638)
175		Commodity	COM	$ (55,566)	$ (29,956)	$ (18,364)	$ (2,035)	$ (4,452)	$ (376)	$ (384)
176		Total Cash Working Capital		$ (4,999,624)	$ (4,445,893)	$ (433,296)	$ (21,454)	$ (86,303)	$ (10,409)	$ (2,270)
177		**Total Rate Base**								
178		Customer		$ 352,248,372	$ 333,749,394	$ 16,375,746	$ 108,093	$ 1,830,835	$ 168,012	$ 16,292
179		Demand		$ 119,831,871	$ 81,395,471	$ 25,864,001	$ 2,521,497	$ 8,676,889	$ 1,133,349	$ 240,664
180		Commodity		$ 1,387,793	$ 748,167	$ 458,643	$ 50,833	$ 111,180	$ 9,386	$ 9,584
181		Total Rate Base		$ 473,468,036	$ 415,893,032	$ 42,698,391	$ 2,680,423	$ 10,618,904	$ 1,310,747	$ 266,540

ALLOCATED COST OF SERVICE

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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1		**Transmission and Distribution Operating Expense**								
2	850-66	**Transmission Expenses**								
3		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	DEM	$ 972,153	$ 718,666	$ 170,572	$ 16,629	$ 57,224	$ 7,474	$ 1,587
5		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6		Total Transmission Expense		$ 972,153	$ 718,666	$ 170,572	$ 16,629	$ 57,224	$ 7,474	$ 1,587
7	870	**Operation Supervision & Engineering**								
8		Customer	871-879CUS	$ 600,373	$ 551,624	$ 42,968	$ 551	$ 4,624	$ 543	$ 63
9		Demand	DEM	$ 114,286	$ 84,486	$ 20,052	$ 1,955	$ 6,727	$ 879	$ 187
10		Commodity	COM	$ 20,346	$ 10,968	$ 6,724	$ 745	$ 1,630	$ 138	$ 141
11		Total Supervision & Engineering		$ 735,005	$ 647,079	$ 69,745	$ 3,251	$ 12,981	$ 1,560	$ 390
12	870	**Odorization**								
13		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15		Commodity	COM	$ 814	$ 439	$ 269	$ 30	$ 65	$ 6	$ 6
16		Total Odorization		$ 814	$ 439	$ 269	$ 30	$ 65	$ 6	$ 6
17	871	**Distribution Load Dispatch**								
18		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Commodity	COM	$ 260,199	$ 140,275	$ 85,992	$ 9,531	$ 20,845	$ 1,760	$ 1,797
21		Total Distribution Load Dispatch		$ 260,199	$ 140,275	$ 85,992	$ 9,531	$ 20,845	$ 1,760	$ 1,797
22	874	**Mains and Services Expenses**								
23		Customer	MSCUS	$ 3,246,664	$ 3,071,955	$ 158,849	$ 731	$ 13,974	$ 1,073	$ 82
24		Demand	DEM	$ 997,962	$ 737,745	$ 175,101	$ 17,071	$ 58,743	$ 7,673	$ 1,629
25		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26		Total Mains & Services		$ 4,244,625	$ 3,809,700	$ 333,949	$ 17,801	$ 72,717	$ 8,746	$ 1,712
27	874	**Odorization**								
28		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Commodity	COM	$ 964	$ 520	$ 319	$ 35	$ 77	$ 7	$ 7
31		Total Odorization		$ 964	$ 520	$ 319	$ 35	$ 77	$ 7	$ 7
32	875	**Meas. & Reg. Station - General**								
33		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Demand	DEM	$ 391,310	$ 289,277	$ 68,659	$ 6,694	$ 23,034	$ 3,009	$ 639

Exhibit CDD-2
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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
35		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36		Total Meas. & Reg. Station - General		$ 391,310	$ 289,277	$ 68,659	$ 6,694	$ 23,034	$ 3,009	$ 639
37	875	**Odorization**								
38		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Commodity	COM	$ 58,361	$ 31,463	$ 19,287	$ 2,138	$ 4,675	$ 395	$ 403
41		Total Odorization		$ 58,361	$ 31,463	$ 19,287	$ 2,138	$ 4,675	$ 395	$ 403
42	876	**Meas. & Reg. Stat. - Industrial**								
43		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Demand	NRDEM	$ 68,073	$ -	$ 45,807	$ 4,466	$ 15,367	$ 2,007	$ 426
45		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Total Meas. & Reg. Stat. - Industrial		$ 68,073	$ -	$ 45,807	$ 4,466	$ 15,367	$ 2,007	$ 426
47	877	**Meas. & Reg. Stat.- City Gate**								
48		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49		Demand	DEM	$ 4,260	$ 3,149	$ 747	$ 73	$ 251	$ 33	$ 7
50		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51		Total Meas. & Reg. Stat. - City Gate		$ 4,260	$ 3,149	$ 747	$ 73	$ 251	$ 33	$ 7
52	878	**Meter & House Reg. Expense**								
53		Customer	MTRGCUS	$ 4,347,173	$ 3,906,496	$ 383,641	$ 6,198	$ 44,358	$ 5,773	$ 707
54		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56		Total Meter & House Reg. Expense		$ 4,347,173	$ 3,906,496	$ 383,641	$ 6,198	$ 44,358	$ 5,773	$ 707
57	879	**Customer Installation Expense**								
58		Customer	METCUS	$ 84,335	$ 76,266	$ 7,034	$ 113	$ 806	$ 103	$ 13
59		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61		Total Customer Install. Expense		$ 84,335	$ 76,266	$ 7,034	$ 113	$ 806	$ 103	$ 13
62	880	**Other Expenses**								
63		Customer	871-879CUS	$ 1,446,075	$ 1,328,656	$ 103,495	$ 1,326	$ 11,138	$ 1,309	$ 151
64		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66		Total Other Expenses		$ 1,446,075	$ 1,328,656	$ 103,495	$ 1,326	$ 11,138	$ 1,309	$ 151
67	880	**Odorization**								
68		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ALLOCATED COST OF SERVICE

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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
69		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70		Commodity	COM	$ 51	$ 27	$ 17	$ 2	$ 4	$ 0	$ 0
71		Total Odorization		$ 51	$ 27	$ 17	$ 2	$ 4	$ 0	$ 0
72	881	**Rents**								
73		Customer	871-879CUS	$ (153,805)	$ (141,316)	$ (11,008)	$ (141)	$ (1,185)	$ (139)	$ (16)
74		Demand	DEM	$ (29,278)	$ (21,644)	$ (5,137)	$ (501)	$ (1,723)	$ (225)	$ (48)
75		Commodity	COM	$ (5,212)	$ (2,810)	$ (1,723)	$ (191)	$ (418)	$ (35)	$ (36)
76		Total Rents		$ (188,295)	$ (165,770)	$ (17,867)	$ (833)	$ (3,326)	$ (400)	$ (100)
77		**Total Distr. & Trans. Op. Expense**								
78		Customer		$ 9,570,816	$ 8,793,681	$ 684,979	$ 8,777	$ 73,717	$ 8,662	$ 999
79		Demand		$ 2,518,766	$ 1,811,679	$ 475,801	$ 46,386	$ 159,622	$ 20,849	$ 4,427
80		Commodity		$ 335,522	$ 180,882	$ 110,885	$ 12,290	$ 26,880	$ 2,269	$ 2,317
81		Total Distr. & Trans. Operations Exp.		$ 12,425,104	$ 10,786,242	$ 1,271,665	$ 67,453	$ 260,218	$ 31,781	$ 7,744
82		**Distribution Maintenance Expenses**								
83	885	**Maintenance Supervision and Engineering**								
84		Customer	887-893CUS	$ 41	$ 38	$ 2	$ 0	$ 0	$ 0	$ 0
85		Demand	887-893DEM	$ 31	$ 17	$ 10	$ 1	$ 3	$ 0	$ 0
86		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87		Total Supervision and Engineering		$ 72	$ 55	$ 12	$ 1	$ 3	$ 0	$ 0
88	886	**Structures and Improvements**								
89		Customer	887-893CUS	$ 204,641	$ 193,839	$ 9,838	$ 43	$ 852	$ 64	$ 5
90		Demand	887-893DEM	$ 157,874	$ 85,717	$ 48,555	$ 4,734	$ 16,289	$ 2,128	$ 452
91		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92		Total Structures and Improvements		$ 362,515	$ 279,556	$ 58,393	$ 4,777	$ 17,141	$ 2,191	$ 457
93	887	**Maintenance of Mains**								
94		Customer	CUS	$ 2,110,004	$ 2,002,005	$ 98,640	$ 397	$ 8,321	$ 593	$ 48
95		Demand	DEM	$ 1,203,699	$ 889,837	$ 211,199	$ 20,590	$ 70,853	$ 9,255	$ 1,965
96		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97		Total Mains		$ 3,313,703	$ 2,891,842	$ 309,839	$ 20,987	$ 79,175	$ 9,847	$ 2,013
98	889	**Maint. of Meas. & Reg. Sta. Equip.- General**								
99		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
100		Demand	DEM	$ 395,845	$ 292,629	$ 69,454	$ 6,771	$ 23,301	$ 3,043	$ 646
101		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102		Total Meas. & Reg. Sta. Equip. - Gen.		$ 395,845	$ 292,629	$ 69,454	$ 6,771	$ 23,301	$ 3,043	$ 646

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
103	889	**Odorization**								
104		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
105		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
106		Commodity	COM	$ 17,985	$ 9,696	$ 5,944	$ 659	$ 1,441	$ 122	$ 124
107		Total Odorization		$ 17,985	$ 9,696	$ 5,944	$ 659	$ 1,441	$ 122	$ 124
108	890	**Meas. & Reg. Sta. Equip. - Industrial**								
109		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110		Demand	NRDEM	$ 585,505	$ -	$ 393,988	$ 38,410	$ 132,176	$ 17,264	$ 3,666
111		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
112		Total Meas. & Reg. Sta. Eq.- Industrial		$ 585,505	$ -	$ 393,988	$ 38,410	$ 132,176	$ 17,264	$ 3,666
113	891	**Meas. & Reg. Sta. Eq.- City Gate**								
114		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
115		Demand	DEM	$ 19,823	$ 14,654	$ 3,478	$ 339	$ 1,167	$ 152	$ 32
116		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117		Total Meas. & Reg. Sta. Eq.- City Gate		$ 19,823	$ 14,654	$ 3,478	$ 339	$ 1,167	$ 152	$ 32
118	892	**Services**								
119		Customer	SERCUS	$ 740,925	$ 698,779	$ 38,136	$ 199	$ 3,501	$ 288	$ 21
120		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122		Total Services		$ 740,925	$ 698,779	$ 38,136	$ 199	$ 3,501	$ 288	$ 21
123	893	**Meters & House Regulators**								
124		Customer	MTRGCUS	$ 7,092	$ 6,373	$ 626	$ 10	$ 72	$ 9	$ 1
125		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
126		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
127		Total Meters & House Regulators		$ 7,092	$ 6,373	$ 626	$ 10	$ 72	$ 9	$ 1
128	894	**Other Equipment**								
129		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
130		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
131		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
132		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
133		**Total Distr. Maintenance Expense**								
134		Customer		$ 3,062,703	$ 2,901,035	$ 147,242	$ 649	$ 12,747	$ 954	$ 75
135		Demand		$ 2,362,777	$ 1,282,854	$ 726,684	$ 70,845	$ 243,789	$ 31,843	$ 6,762
136		Commodity		$ 17,985	$ 9,696	$ 5,944	$ 659	$ 1,441	$ 122	$ 124

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
137		Total Distr. Maintenance Expense		$ 5,443,464	$ 4,193,585	$ 879,871	$ 72,153	$ 257,977	$ 32,918	$ 6,961
138		**Total Oper. & Maint. Expense**								
139		Customer		$ 12,633,519	$ 11,694,717	$ 832,222	$ 9,426	$ 86,463	$ 9,616	$ 1,074
140		Demand		$ 4,881,542	$ 3,094,533	$ 1,202,485	$ 117,231	$ 403,411	$ 52,692	$ 11,189
141		Commodity		$ 353,507	$ 190,578	$ 116,828	$ 12,949	$ 28,320	$ 2,391	$ 2,441
142		Total Operations & Maint. Expense		$ 17,868,568	$ 14,979,827	$ 2,151,536	$ 139,606	$ 518,195	$ 64,699	$ 14,705
143		**Customer Accounts Expense**								
144	901	**Supervision**								
145		Customer	902-904CUS	$ 154,499	$ 146,863	$ 7,003	$ 69	$ 508	$ 50	$ 6
146		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
147		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148		Total Supervision		$ 154,499	$ 146,863	$ 7,003	$ 69	$ 508	$ 50	$ 6
149	902	**Meter Reading Expense**								
150		Customer	METCUS	$ 1,351,191	$ 1,221,912	$ 112,695	$ 1,807	$ 12,921	$ 1,650	$ 207
151		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
153		Total Meter Reading Expense		$ 1,351,191	$ 1,221,912	$ 112,695	$ 1,807	$ 12,921	$ 1,650	$ 207
154	903	**Customer Accounting**								
155		Customer	903CUS	$ 4,115,966	$ 3,972,244	$ 136,385	$ 254	$ 6,625	$ 427	$ 31
156		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
157		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
158		Total Customer Accounting		$ 4,115,966	$ 3,972,244	$ 136,385	$ 254	$ 6,625	$ 427	$ 31
159	904	**Bad Debt Expense**								
160		Customer	904CUS	$ 677,271	$ 646,588	$ 29,420	$ 673	$ 673	$ (84)	$ -
161		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
162		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
163		Total Bad Debt Expense		$ 677,271	$ 646,588	$ 29,420	$ 673	$ 673	$ (84)	$ -
164	905	**Miscellaneous Customer Accounts**								
165		Customer	902-904CUS	$ 342,471	$ 325,545	$ 15,523	$ 152	$ 1,127	$ 111	$ 13
166		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
167		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
168		Total Misc. Customer Accounts		$ 342,471	$ 325,545	$ 15,523	$ 152	$ 1,127	$ 111	$ 13
169	907-910	**Customer Service Expense**								
170		Customer	CUS	$ 837,188	$ 794,337	$ 39,137	$ 158	$ 3,302	$ 235	$ 19

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
171		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
172		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173		Total Customer Service Expense		$ 837,188	$ 794,337	$ 39,137	$ 158	$ 3,302	$ 235	$ 19
174		**Sales and Advertising Expense**								
175	912	**Demonstrating and Selling**								
176		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
177		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
178		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179		Total Demon. and Selling Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -
180	913	**Advertising**								
181		Customer	CUS	$ 23,611	$ 22,402	$ 1,104	$ 4	$ 93	$ 7	$ 1
182		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
183		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
184		Total Advertising		$ 23,611	$ 22,402	$ 1,104	$ 4	$ 93	$ 7	$ 1
185		**Administrative & General Exp.**								
186	921-32	**Administrative & General Expenses**								
187		Customer	OPEXPCUS	$ 23,122,526	$ 21,650,241	$ 1,319,789	$ 12,446	$ 125,876	$ 12,804	$ 1,370
188		Demand	OPEXPDEM	$ 2,967,828	$ 1,945,118	$ 688,186	$ 67,092	$ 230,873	$ 30,156	$ 6,404
189		Commodity	COM	$ 220,893	$ 119,084	$ 73,001	$ 8,091	$ 17,696	$ 1,494	$ 1,525
190		Total Administrative & General Exp.		$ 26,311,246	$ 23,714,443	$ 2,080,976	$ 87,629	$ 374,446	$ 44,454	$ 9,299
191		**Depreciation & Amortization Expense**								
192	301-03	**Intangible Plant**								
193		Customer	CUS	$ 24,241	$ 23,000	$ 1,133	$ 5	$ 96	$ 7	$ 1
194		Demand	DEM	$ 8,074	$ 5,969	$ 1,417	$ 138	$ 475	$ 62	$ 13
195		Commodity	COM	$ 50	$ 27	$ 16	$ 2	$ 4	$ 0	$ 0
196		Total Intangible Plant		$ 32,365	$ 28,996	$ 2,566	$ 144	$ 575	$ 69	$ 14
197	365	**Land and Land Rights**								
198		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
199		Demand	DEM	$ 32	$ 24	$ 6	$ 1	$ 2	$ 0	$ 0
200		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
201		Total Land and Land Rights		$ 32	$ 24	$ 6	$ 1	$ 2	$ 0	$ 0
202	366	**Meas. and Reg. Station Structures**								
203		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
204		Demand	DEM	$ 95	$ 70	$ 17	$ 2	$ 6	$ 1	$ 0

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
205		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
206		Total Measuring and Reg. Stat. Struct.		$ 95	$ 70	$ 17	$ 2	$ 6	$ 1	$ 0
207	367	**Transmission Mains**								
208		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
209		Demand	DEM	$ 213,908	$ 158,132	$ 37,532	$ 3,659	$ 12,591	$ 1,645	$ 349
210		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
211		Total Transmission Mains		$ 213,908	$ 158,132	$ 37,532	$ 3,659	$ 12,591	$ 1,645	$ 349
212	368	**Compression Station Equipment**								
213		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
214		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
215		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
216		Total Compression Sta. Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
217	369	**Meas. & Reg. Station Equipment**								
218		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
219		Demand	DEM	$ 50,155	$ 37,077	$ 8,800	$ 858	$ 2,952	$ 386	$ 82
220		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
221		Total Meas. & Reg. Stat. Equipment		$ 50,155	$ 37,077	$ 8,800	$ 858	$ 2,952	$ 386	$ 82
222	371	**Other Equipment**								
223		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
224		Demand	DEM	$ 1,201	$ 888	$ 211	$ 21	$ 71	$ 9	$ 2
225		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
226		Total Other Equipment		$ 1,201	$ 888	$ 211	$ 21	$ 71	$ 9	$ 2
227	375	**Structures and Improvements**								
228		Customer	376-379CUS	$ 690	$ 655	$ 32	$ 0	$ 3	$ 0	$ 0
229		Demand	DEM	$ 445	$ 329	$ 78	$ 8	$ 26	$ 3	$ 1
230		Commodity	COM	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
231		Total Structures and Improvements		$ 1,136	$ 984	$ 111	$ 8	$ 29	$ 4	$ 1
232	376	**Distribution Mains**								
233		Customer	CUS	$ 4,886,752	$ 4,636,628	$ 228,449	$ 920	$ 19,272	$ 1,373	$ 110
234		Demand	DEM	$ 2,787,756	$ 2,060,854	$ 489,135	$ 47,686	$ 164,096	$ 21,434	$ 4,551
235		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
236		Total Distribution Mains		$ 7,674,509	$ 6,697,482	$ 717,584	$ 48,606	$ 183,368	$ 22,807	$ 4,662
237	377	**Compressor Station Equipment**								
238		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
239		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
240		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
241		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
242	378	**Meas. & Reg. Sta. Equip. - General**								
243		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
244		Demand	DEM	$ 296,057	$ 218,861	$ 51,946	$ 5,064	$ 17,427	$ 2,276	$ 483
245		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
246		Total Meas. & Reg. Sta. Eq.- General		$ 296,057	$ 218,861	$ 51,946	$ 5,064	$ 17,427	$ 2,276	$ 483
247	378	**Odorization Tank**								
248		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
249		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
250		Commodity	COM	$ 14,693	$ 7,921	$ 4,856	$ 538	$ 1,177	$ 99	$ 101
251		Total Odorization Tank		$ 14,693	$ 7,921	$ 4,856	$ 538	$ 1,177	$ 99	$ 101
252	379	**Meas.& Reg. Sta. Equip.- City Gate**								
253		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
254		Demand	DEM	$ 40,742	$ 30,119	$ 7,149	$ 697	$ 2,398	$ 313	$ 67
255		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
256		Total Meas. & Reg. Sta. Eq.- City Gate		$ 40,742	$ 30,119	$ 7,149	$ 697	$ 2,398	$ 313	$ 67
257	379	**Odorization Tank**								
258		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
259		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
260		Commodity	COM	$ 4,903	$ 2,643	$ 1,621	$ 180	$ 393	$ 33	$ 34
261		Total Odorization Tank		$ 4,903	$ 2,643	$ 1,621	$ 180	$ 393	$ 33	$ 34
262	380	**Services**								
263		Customer	SERCUS	$ 4,742,152	$ 4,472,410	$ 244,085	$ 1,272	$ 22,409	$ 1,842	$ 136
264		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
265		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
266		Total Services		$ 4,742,152	$ 4,472,410	$ 244,085	$ 1,272	$ 22,409	$ 1,842	$ 136
267	381	**Meters**								
268		Customer	METCUS	$ 2,639,514	$ 2,386,970	$ 220,146	$ 3,529	$ 25,241	$ 3,223	$ 404
269		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
270		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
271		Total Meters		$ 2,639,514	$ 2,386,970	$ 220,146	$ 3,529	$ 25,241	$ 3,223	$ 404
272	382	**Meter Installations**								

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
273		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
274		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
275		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
276		Total Meter Installations		$ -	$ -	$ -	$ -	$ -	$ -	$ -
277	383	**House Regulators**								
278		Customer	REGCUS	$ 232,452	$ 202,685	$ 25,796	$ 428	$ 3,071	$ 425	$ 48
279		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
280		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
281		Total House Regulators		$ 232,452	$ 202,685	$ 25,796	$ 428	$ 3,071	$ 425	$ 48
282	385	**Meas. & Reg. Sta. Equip. - Industrial**								
283		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
284		Demand	NRDEM	$ 297,860	$ -	$ 200,431	$ 19,540	$ 67,241	$ 8,783	$ 1,865
285		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
286		Total Meas. & Reg. Stat. Eq.- Indus.		$ 297,860	$ -	$ 200,431	$ 19,540	$ 67,241	$ 8,783	$ 1,865
287	385	**Odorization Tank**								
288		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
289		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
290		Commodity	COM	$ 1,029	$ 554	$ 340	$ 38	$ 82	$ 7	$ 7
291		Total Odorization Tank		$ 1,029	$ 554	$ 340	$ 38	$ 82	$ 7	$ 7
292	386	**Other Prop.- Customer Premises**								
293		Customer	CUS	$ (1,701)	$ (1,614)	$ (80)	$ (0)	$ (7)	$ (0)	$ (0)
294		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
295		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
296		Total Other Prop. - Customer Premises		$ (1,701)	$ (1,614)	$ (80)	$ (0)	$ (7)	$ (0)	$ (0)
297	387	**Other Equipment**								
298		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
299		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
300		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
301		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
302	389-98	**General Plant**								
303		Customer	GENPTCUS	$ 4,509,586	$ 4,253,908	$ 231,368	$ 1,408	$ 20,964	$ 1,776	$ 162
304		Demand	DISPLTDEM	$ 595,539	$ 401,192	$ 130,777	$ 12,749	$ 43,873	$ 5,731	$ 1,217
305		Commodity	COM	$ 4,909	$ 2,647	$ 1,622	$ 180	$ 393	$ 33	$ 34
306		Total General Plant		$ 5,110,034	$ 4,657,747	$ 363,767	$ 14,337	$ 65,230	$ 7,540	$ 1,413

Exhibit CDD-2
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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
307	4073	**Pension & FAS 106 Amort. Expense**								
308		Customer	CUS	$ 276,921	$ 262,747	$ 12,946	$ 52	$ 1,092	$ 78	$ 6
309		Demand	DEM	$ 50,248	$ 37,146	$ 8,816	$ 860	$ 2,958	$ 386	$ 82
310		Commodity	COM	$ 3,677	$ 1,982	$ 1,215	$ 135	$ 295	$ 25	$ 25
311		Total Pension & FAS 106 Amort. Exp.		$ 330,846	$ 301,875	$ 22,977	$ 1,046	$ 4,344	$ 489	$ 114
312		**Total Depreciation & Amort. Exp.**								
313		Customer		$ 17,310,608	$ 16,237,389	$ 963,875	$ 7,613	$ 92,140	$ 8,723	$ 867
314		Demand		$ 4,342,113	$ 2,950,661	$ 936,313	$ 91,282	$ 314,116	$ 41,029	$ 8,712
315		Commodity		$ 29,262	$ 15,775	$ 9,671	$ 1,072	$ 2,344	$ 198	$ 202
316		Total Depreciation & Amort. Expense		$ 21,681,983	$ 19,203,825	$ 1,909,859	$ 99,967	$ 408,600	$ 49,950	$ 9,782
317		**Taxes Other Than Income**								
318	4081	**Payroll and Other Taxes**								
319		Customer	OPEXPCUS	$ 2,196,761	$ 2,056,886	$ 125,387	$ 1,182	$ 11,959	$ 1,216	$ 130
320		Demand	OPEXPDEM	$ 398,610	$ 261,250	$ 92,431	$ 9,011	$ 31,009	$ 4,050	$ 860
321		Commodity	COM	$ 29,169	$ 15,725	$ 9,640	$ 1,068	$ 2,337	$ 197	$ 201
322		Total Payroll and Other Taxes		$ 2,624,541	$ 2,333,861	$ 227,457	$ 11,262	$ 45,304	$ 5,464	$ 1,192
323		**Ad Valorem Taxes**								
324		Customer	CUS	$ 3,284,495	$ 3,116,381	$ 153,546	$ 618	$ 12,953	$ 923	$ 74
325		Demand	DEM	$ 1,093,945	$ 808,701	$ 191,942	$ 18,713	$ 64,393	$ 8,411	$ 1,786
326		Commodity	COM	$ 6,763	$ 3,646	$ 2,235	$ 248	$ 542	$ 46	$ 47
327		Total Ad Valorem Taxes		$ 4,385,203	$ 3,928,728	$ 347,723	$ 19,578	$ 77,888	$ 9,379	$ 1,907
328		**Revenue Related Taxes**								
329		Customer	TOTREVCUS	$ 141,127	$ 104,097	$ 31,342	$ 1,229	$ 4,024	$ 348	$ 87
330		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
331		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
332		Total Revenue Related Taxes		$ 141,127	$ 104,097	$ 31,342	$ 1,229	$ 4,024	$ 348	$ 87
333		**Total Taxes Other Than Income**								
334		Customer		$ 5,622,383	$ 5,277,363	$ 310,275	$ 3,030	$ 28,936	$ 2,487	$ 291
335		Demand		$ 1,492,556	$ 1,069,951	$ 284,372	$ 27,724	$ 95,402	$ 12,461	$ 2,646
336		Commodity		$ 35,932	$ 19,371	$ 11,875	$ 1,316	$ 2,879	$ 243	$ 248
337		Total Taxes Other Than Income		$ 7,150,871	$ 6,366,686	$ 606,522	$ 32,070	$ 127,216	$ 15,191	$ 3,186
338		**Interest on Customer Deposits**								
339		Customer	DEPCUS	$ 150,792	$ 88,981	$ 60,974	$ 678	$ 143	$ 16	$ -
340		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
341		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
342		Total Interest on Cust. Deposits		$ 150,792	$ 88,981	$ 60,974	$ 678	$ 143	$ 16	$ -
343		**Required Return**								
344		Customer	CUS	$ 27,921,150	$ 26,492,028	$ 1,305,278	$ 5,256	$ 110,114	$ 7,844	$ 631
345		Demand	DEM	$ 9,498,536	$ 7,021,812	$ 1,666,597	$ 162,478	$ 559,112	$ 73,030	$ 15,508
346		Commodity	COM	$ 110,004	$ 59,304	$ 36,355	$ 4,029	$ 8,813	$ 744	$ 760
347		Total Required Return		$ 37,529,690	$ 33,573,144	$ 3,008,229	$ 171,763	$ 678,038	$ 81,618	$ 16,898
348		**Income Taxes**								
349		Customer	CUS	$ 5,844,315	$ 5,545,178	$ 273,214	$ 1,100	$ 23,048	$ 1,642	$ 132
350		Demand	DEM	$ 1,988,186	$ 1,469,770	$ 348,844	$ 34,009	$ 117,031	$ 15,286	$ 3,246
351		Commodity	COM	$ 23,026	$ 12,413	$ 7,610	$ 843	$ 1,845	$ 156	$ 159
352		Total Income Taxes		$ 7,855,526	$ 7,027,361	$ 629,667	$ 35,952	$ 141,924	$ 17,084	$ 3,537
353		**Total Cost of Service Before**								
354		**Revenue Credits**								
355		Customer		$ 100,107,489	$ 94,115,788	$ 5,406,893	$ 42,666	$ 491,970	$ 45,529	$ 4,642
356		Demand		$ 25,170,760	$ 17,551,845	$ 5,126,797	$ 499,815	$ 1,719,945	$ 224,654	$ 47,705
357		Commodity		$ 772,623	$ 416,526	$ 255,340	$ 28,300	$ 61,897	$ 5,225	$ 5,336
358		**Total Cost of Service Before Revenue Credits**		$ 126,050,873	$ 112,084,159	$ 10,789,030	$ 570,781	$ 2,273,812	$ 275,408	$ 57,683

ALLOCATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Customer Cost Allocation Factors**								
2									
3	Total Customers		3,718,286	3,527,969	173,825	700	14,664	1,045	84
4	**Total Customers Factor (CUS)**	**CUS**	**1.00000**	**0.94882**	**0.04675**	**0.00019**	**0.00394**	**0.00028**	**0.00002**
5									
6	Services Weighting			1.00000	1.10767	1.43311	1.20545	1.39076	1.27428
7	Weighted Customers		3,740,750	3,527,969	192,541	1,003	17,677	1,453	107
8	**Weighted Services Customer Factor (SERCUS)**	**SERCUS**	**1.00000**	**0.94312**	**0.05147**	**0.00027**	**0.00473**	**0.00039**	**0.00003**
9									
10	Meters Weighting			1.00000	1.87187	7.45262	2.54411	4.56058	7.11284
11	Weighted Customers		3,901,232	3,527,969	325,379	5,216	37,307	4,764	597
12	**Weighted Meters Customer Factor (METCUS)**	**METCUS**	**1.00000**	**0.90432**	**0.08340**	**0.00134**	**0.00956**	**0.00122**	**0.00015**
13									
14	Regulators Weighting			1.00000	2.58306	10.64409	3.64475	7.08421	9.94514
15	Weighted Customers		4,046,101	3,527,969	449,001	7,450	53,446	7,401	835
16	**Weighted Regulators Customer Factor (REGCUS)**	**REGCUS**	**1.00000**	**0.87194**	**0.11097**	**0.00184**	**0.01321**	**0.00183**	**0.00021**
17									
18	Meters and Regulators Weighting			1.00000	1.99320	7.99706	2.73187	4.99109	7.59601
19	Weighted Customers		3,925,945	3,527,969	346,468	5,597	40,060	5,214	638
20	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS)**	**MTRGCUS**	**1.00000**	**0.89863**	**0.08825**	**0.00143**	**0.01020**	**0.00133**	**0.00016**
21									
22	Non-Residential Customers		190,318	0	173,825	700	14,664	1,045	84
23	**Non-Residential Customers Factor (NRCUS)**	**NRCUS**	**1.00000**	**0.00000**	**0.91334**	**0.00368**	**0.07705**	**0.00549**	**0.00044**
24									
25	**Customer Cost Allocation Factors**								
26									
27	Distribution Plant Customer Costs		$ 481,595,709	$ 452,280,159	$ 26,370,959	$ 195,614	$ 2,495,979	$ 230,794	$ 22,204
28	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	**DISPLTCUS**	**1.00000**	**0.93913**	**0.05476**	**0.00041**	**0.00518**	**0.00048**	**0.00005**
29									
30	Account 376-379 Customer Costs		$ 216,872,700	$ 205,772,242	$ 10,138,517	$ 40,823	$ 855,288	$ 60,931	$ 4,899
31	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	**376-379CUS**	**1.00000**	**0.94882**	**0.04675**	**0.00019**	**0.00394**	**0.00028**	**0.00002**
32									
33	Total Revenue (inc. cost of gas)		$ 175,403,465	$ 129,379,490	$ 38,954,004	$ 1,527,956	$ 5,001,287	$ 432,647	$ 108,082
34	**Total Revenue (TOTREVCUS)**	**TOTREVCUS**	**1.00000**	**0.73761**	**0.22208**	**0.00871**	**0.02851**	**0.00247**	**0.00062**
35									
36	Mains - Customer Cost Factor		**0.53882**	**0.51124**	**0.02519**	**0.00010**	**0.00212**	**0.00015**	**0.00001**
37	Services - Customer Cost Factor		**0.46118**	**0.43495**	**0.02374**	**0.00012**	**0.00218**	**0.00018**	**0.00001**
38	**Mains & Svcs. Customer Factor (MSCUS)**	**MSCUS**	**1.00000**	**0.94619**	**0.04893**	**0.00023**	**0.00430**	**0.00033**	**0.00003**
39									

ALLOCATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
40	Total Plant Customer		$ 552,654,402	$ 519,701,768	$ 29,692,861	$ 208,990	$ 2,776,215	$ 250,758	$ 23,810
41	**Total Plant Factor (TPLTCUS)**	**TPLTCUS**	**1.00000**	**0.94037**	**0.05373**	**0.00038**	**0.00502**	**0.00045**	**0.00004**
42									
43	Account 871-879 Customer Costs		$ 7,678,172	$ 7,054,717	$ 549,524	$ 7,041	$ 59,139	$ 6,949	$ 802
44	**Account 871-879 Cust. Costs Factor (871-879CUS)**	**871-879CUS**	**1.00000**	**0.91880**	**0.07157**	**0.00092**	**0.00770**	**0.00091**	**0.00010**
45									
46	Account 887-893 Customer Costs		$ 2,858,021	$ 2,707,158	$ 137,402	$ 606	$ 11,895	$ 890	$ 70
47	**Account 887-893 Cust. Costs Factor (887-893CUS)**	**887-893CUS**	**1.00000**	**0.94721**	**0.04808**	**0.00021**	**0.00416**	**0.00031**	**0.00002**
48									
49	Account 903 Customer		$ 4,115,966	$ 3,972,244	$ 136,385	$ 254	$ 6,625	$ 427	$ 31
50	**Account 903 Customer Factor (903CUS)**	**903CUS**	**1.00000**	**0.96508**	**0.03314**	**0.00006**	**0.00161**	**0.00010**	**0.00001**
51									
52	**Customer Cost Allocation Factors**								
53									
54	Account 904 Customer		$ 677,271	$ 646,588	$ 29,420	$ 673	$ 673	$ (84)	$ -
55	**Account 904 Customer Factor (904CUS)**	**904CUS**	**1.00000**	**0.95470**	**0.04344**	**0.00099**	**0.00099**	**-0.00012**	**0.00000**
56									
57	Accounts 902-904 Customer		$ 6,144,429	$ 5,840,744	$ 278,500	$ 2,734	$ 20,220	$ 1,993	$ 238
58	**Accts. 902-904 Customer Factor (902-904CUS)**	**902-904CUS**	**1.00000**	**0.95058**	**0.04533**	**0.00044**	**0.00329**	**0.00032**	**0.00004**
59									
60	Operating Expense Customer		$ 37,446,324	$ 35,061,997	$ 2,137,364	$ 20,156	$ 203,853	$ 20,736	$ 2,218
61	**Operating Exp. Customer Factor (OPEXPCUS)**	**OPEXPCUS**	**1.00000**	**0.93633**	**0.05708**	**0.00054**	**0.00544**	**0.00055**	**0.00006**
62									
63	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 39,919,126	$ 37,489,181	$ 2,185,870	$ 16,214	$ 206,890	$ 19,130	$ 1,841
64	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 30,237,053	$ 28,689,394	$ 1,413,543	$ 5,692	$ 119,247	$ 8,495	$ 683
65	Total General Plant Customer Costs		$ 70,156,179	$ 66,178,574	$ 3,599,413	$ 21,906	$ 326,137	$ 27,625	$ 2,524
66	**General Plant Customer Factor (GENPTCUS)**	**GENPTCUS**	**1.00000**	**0.94330**	**0.05131**	**0.00031**	**0.00465**	**0.00039**	**0.00004**
67									
68	Customer Deposits		$ (7,853,752)	$ (4,634,440)	$ (3,175,747)	$ (35,306)	$ (7,435)	$ (824)	$ -
69	**Customer Deposits Factor (DEPCUS)**	**DEPCUS**	**1.00000**	**0.59009**	**0.40436**	**0.00450**	**0.00095**	**0.00010**	**0.00000**
70									
71	**Demand Cost Allocation Factors**								
72									
73	System Demand								
74	**System Demand Factor (DEM)**	**DEM**	**1.00000**	**0.73925**	**0.17546**	**0.01711**	**0.05886**	**0.00769**	**0.00163**
75									
76	Non-Residential Demand								
77	**Non-Residential Demand Factor (NRDEM)**	**NRDEM**	**1.00000**	**0.00000**	**0.67290**	**0.06560**	**0.22575**	**0.02949**	**0.00626**
78									

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
79	Distribution Plant Demand		$ 156,076,970	$ 105,143,204	$ 34,273,527	$ 3,341,347	$ 11,498,128	$ 1,501,850	$ 318,914
80	**Distribution Plant Demand Factor (DISPLTDEM)**	**DISPLTDEM**	**1.00000**	**0.67366**	**0.21959**	**0.02141**	**0.07367**	**0.00962**	**0.00204**
81									
82	**Demand Cost Allocation Factors**								
83									
84	Total Plant Demand		$ 184,069,015	$ 125,836,381	$ 39,184,963	$ 3,820,166	$ 13,145,823	$ 1,717,067	$ 364,615
85	**Total Plant Demand Factor (TPLTDEM)**	**TPLTDEM**	**1.00000**	**0.68364**	**0.21288**	**0.02075**	**0.07142**	**0.00933**	**0.00198**
86									
87	Operating Expense Demand		$ 9,223,655	$ 6,045,194	$ 2,138,799	$ 208,513	$ 717,527	$ 93,721	$ 19,901
88	**Operating Expense Demand Factor (OPEXPDEM)**	**OPEXPDEM**	**1.00000**	**0.65540**	**0.23188**	**0.02261**	**0.07779**	**0.01016**	**0.00216**
89									
90	Acct. 887-893 Demand		$ 2,204,871	$ 1,197,120	$ 678,120	$ 66,110	$ 227,497	$ 29,715	$ 6,310
91	**Acct. 887-893 Demand Factor (887-893DEM)**	**887-893DEM**	**1.00000**	**0.54294**	**0.30756**	**0.02998**	**0.10318**	**0.01348**	**0.00286**
92									
93	Rate Base Demand		$ 119,831,871	$ 81,395,471	$ 25,864,001	$ 2,521,497	$ 8,676,889	$ 1,133,349	$ 240,664
94	**Rate Base Demand Factor (RBDEM)**	**RBDEM**	**1.00000**	**0.67925**	**0.21584**	**0.02104**	**0.07241**	**0.00946**	**0.00201**
95									
96	**Commodity Cost Allocation Factors**								
97									
98	Annual Distribution Volumes (Ccf)		195,877,421	105,598,596	64,734,346	7,174,749	15,692,266	1,324,758	1,352,707
99	**Distribution Commodity Factor (COM)**	**COM**	**1.00000**	**0.53911**	**0.33048**	**0.03663**	**0.08011**	**0.00676**	**0.00691**

CLASS REVENUE ALLOCATION

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
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CLASS REVENUE ALLOCATION

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Current Revenue-to-Cost Ratio (1)	0.8648	0.7630	1.7364	2.1690	1.3335	1.8917
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
5	Rate Design Revenue Increase	$ 17,046,666	$ 26,560,535	$ (7,944,915)	$ (667,238)	$ (850,278)	$ (51,438)
6	% Increase - Non-Gas Revenue (2)	15.64%	31.06%	-42.41%	-53.90%	-25.01%	-47.14%
7	% Increase - Total Revenue (3)	9.43%	19.78%	-20.23%	-43.30%	-15.48%	-47.02%
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)						
9	Revenue-to-Cost Ratio	1.0000	0.9321	1.5891	1.9352	1.2668	1.7134
10	Rate Design Revenue Increase	$ 17,046,666	$ 18,949,440	$ (1,588,983)	$ (133,448)	$ (170,056)	$ (10,288)
11	% Increase - Non-Gas Revenue (2)	15.64%	22.16%	-8.48%	-10.78%	-5.00%	-9.43%
12	% Increase - Total Revenue (3)	9.43%	14.11%	-4.05%	-8.66%	-3.10%	-9.40%
13	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)						
14	Revenue-to-Cost Ratio	1.0000	0.9151	1.7364	2.1690	1.3335	1.8917
15	Rate Design Revenue Increase	$ 17,046,666	$ 17,046,666	$ -	$ -	$ -	$ -
16	% Increase - Non-Gas Revenue (2)	15.64%	19.93%	0.00%	0.00%	0.00%	0.00%
17	% Increase - Total Revenue (3)	9.43%	12.69%	0.00%	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.

STUDY SUMMARY

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY SUMMARY

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Customer Costs	$ 83,349,799	$ 78,268,234	$ 4,618,306	$ 38,909	$ 375,195	$ 44,584	$ 4,571
2	Demand Costs	$ 22,905,246	$ 15,988,700	$ 4,677,581	$ 487,065	$ 1,469,691	$ 232,779	$ 49,430
3	Commodity Costs	$ 646,513	$ 345,709	$ 212,704	$ 24,534	$ 53,441	$ 5,010	$ 5,115
4	Cost of Service Before Revenue Credits	$ 106,901,558	$ 94,602,642	$ 9,508,590	$ 550,509	$ 1,898,327	$ 282,373	$ 59,117
5	Revenues Credited to Cost of Service (1)	$ 3,897,918	$ 3,625,476	$ 226,015	$ 9,101	$ 31,701	$ 4,652	$ 973
6	Total Cost of Service	$ 103,003,640	$ 90,977,166	$ 9,282,576	$ 541,408	$ 1,866,626	$ 277,721	$ 58,144
7	Revenue at Current Rates	$ 87,161,240	$ 67,833,765	$ 15,479,042	$ 955,148	$ 2,410,383	$ 375,105	$ 107,796
8	Revenue Deficiency	$ 15,842,399	$ 23,143,400	$ (6,196,467)	$ (413,740)	$ (543,757)	$ (97,385)	$ (49,652)
9	Revenue-to-Cost Ratios:							
10	Current Revenue	0.8518	0.7554	1.6517	1.7516	1.2864	1.3449	1.8399
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge, special contract, and other revenue are used to offset each class' cost of service. Service charge revenue is directly assigned to classes and is included in the revenue credit on line 5. Allocation of the remaining revenues to be credited is based on each class' cost of service relative to the total cost of service on line 4. The components of the total revenue credit are as follows:

Service Charges	$ 2,138,318
Special Contract	$ 1,739,116
Irrigation	$ 20,483
	$ 3,897,918

STUDY SUMMARY FOR REV. ALLOC.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY SUMMARY FOR REVENUE ALLOCATION

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Customer Costs	$ 83,349,799	$ 78,268,234	$ 4,618,306	$ 38,909	$ 419,779	$ 4,571
2	Demand Costs	$ 22,905,246	$ 15,988,700	$ 4,677,581	$ 487,065	$ 1,702,470	$ 49,430
3	Commodity Costs	$ 646,513	$ 345,709	$ 212,704	$ 24,534	$ 58,451	$ 5,115
4	Cost of Service Before Revenue Credits	$ 106,901,558	$ 94,602,642	$ 9,508,590	$ 550,509	$ 2,180,699	$ 59,117
5	Revenues Credited to Cost of Service	$ 3,897,918	$ 3,625,476	$ 226,015	$ 9,101	$ 36,353	$ 973
6	Total Cost of Service	$ 26,044,857	$ 90,977,166	$ 9,282,576	$ 541,408	$ 2,144,347	$ 58,144
7	Revenue at Current Rates	$ 87,161,240	$ 67,833,765	$ 15,479,042	$ 955,148	$ 2,785,489	$ 107,796
8	Revenue Deficiency	$ 15,842,399	$ 23,143,400	$ (6,196,467)	$ (413,740)	$ (641,142)	$ (49,652)
9	Revenue-to-Cost Ratios						
10	Current Revenue	0.8518	0.7554	1.6517	1.7516	1.2940	1.8399
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
	Customer and Demand Costs Per Bill		$ 31.21	$ 61.27	$ 806.82	$ 169.31	$ 642.87
	Commodity Cost Per Cff	$ 0.0038					

CLASSIFIED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	301	Organization	NONINTPLT	$ 57,564	$ 41,665	$ 15,825	$ 74
2	302	Franchises and Consents	NONINTPLT	$ 386,918	$ 280,053	$ 106,367	$ 499
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 749,615	$ 542,573	$ 206,076	$ 966
4		Total Intangible Plant		$ 1,194,097	$ 864,291	$ 328,268	$ 1,539
5							
6		Transmission Plant					
7	365	Land and Land Rights	DEM	$ 92,083	$ -	$ 92,083	$ -
8	366	Meas. and Reg. Station Structures	DEM	$ 2,346	$ -	$ 2,346	$ -
9	367	Transmission Mains	DEM	$ 12,223,339	$ -	$ 12,223,339	$ -
10	368	Compression Station Equipment	DEM	$ -	$ -	$ -	$ -
11	369	Measuring and Reg. Station Equipment	DEM	$ 2,390,734	$ -	$ 2,390,734	$ -
12	371	Other Equipment	DEM	$ 45,840	$ -	$ 45,840	$ -
13		Total Transmission Plant		$ 14,754,342	$ -	$ 14,754,342	$ -
14							
15		Distribution Plant					
16	374	Land & Land Rights	DIS376-379	$ 5,803,378	$ 3,356,990	$ 2,445,104	$ 1,284
17	375	Structures and Improvements	DIS376-379	$ 35,311	$ 20,426	$ 14,877	$ 8
18	376	Distribution Mains	MAINS	$ 303,196,900	$ 183,343,142	$ 119,853,758	$ -
19	378	Meas. & Reg. Sta. Equip.- General	DEM	$ 12,264,948	$ -	$ 12,264,948	$ -
20	378	Odorization Tank	COM	$ 635,549	$ -	$ -	$ 635,549
21	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 1,421,467	$ -	$ 1,421,467	$ -
22	379	Odorization Tank	COM	$ 70,153	$ -	$ -	$ 70,153
23	380	Services	CUS	$ 152,423,104	$ 152,423,104	$ -	$ -
24	381	Meters	CUS	$ 53,737,506	$ 53,737,506	$ -	$ -

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CLASSIFIED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
25	382	Meter Installations	CUS	$ (459,739)	$ (459,739)	$ -	$ -
26	383	House Regulators	CUS	$ 7,382,713	$ 7,382,713	$ -	$ -
27	385	Meas. & Reg. Sta. Equipment - Industrial	DEM	$ 11,374,459	$ -	$ 11,374,459	$ -
28	385	Odorization Tank	COM	$ 47,838	$ -	$ -	$ 47,838
29	386	Other Property - Customer Premises	CUS	$ 249,867	$ 249,867	$ -	$ -
30	387	Other Equipment		$ -	$ -	$ -	$ -
31		Total Distribution Plant		$ 548,183,452	$ 400,054,007	$ 147,374,612	$ 754,833
32							
33		General Plant					
34	389	Land & Land Rights	GENPLT	$ 216,612	$ 214,792	$ 1,811	$ 9
35	390	Structures & Improvements	GENPLT	$ 5,567,557	$ 4,547,622	$ 1,014,738	$ 5,197
36	391	Office Furniture and Equipment	GENPLT	$ 26,086,242	$ 25,363,351	$ 719,207	$ 3,684
37	392	Transportation Equipment	GENPLT	$ 12,761,573	$ 9,313,157	$ 3,430,844	$ 17,572
38	393	Stores Equipment	GENPLT	$ 5,387	$ 3,931	$ 1,448	$ 7
39	394	Tools, Shop & Garage	GENPLT	$ 6,752,329	$ 4,929,880	$ 1,813,163	$ 9,287
40	394	Odorization Tank	COM	$ -	$ -	$ -	$ -
41	396	Major Work Equipment	GENPLT	$ 1,505,661	$ 1,098,803	$ 404,785	$ 2,073
42	397	Communication Equipment	GENPLT	$ 16,148,026	$ 11,903,461	$ 4,222,935	$ 21,629
43	398	Miscellaneous General Plant	GENPLT	$ 130,360	$ 95,134	$ 35,046	$ 180
44		Total General Plant		$ 69,173,746	$ 57,470,130	$ 11,643,977	$ 59,639
45							
46		Total Plant in Service		$ 633,305,637	$ 458,388,428	$ 174,101,199	$ 816,010

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CLASSIFIED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
47							
48		Depreciation & Amortization Reserve					
49		Intangible Plant	NONINTPLT	$ (1,165,261)	$ (843,419)	$ (320,340)	$ (1,501)
50		Transmission Plant	DEM	$ (3,636,481)	$ -	$ (3,636,481)	$ -
51		Distribution Plant	DISPLTRES	$ (126,332,395)	$ (94,290,679)	$ (32,046,790)	$ 5,074
52		General Plant	GENPLTRES	$ (24,585,803)	$ (20,081,329)	$ (4,481,520)	$ (22,954)
53		Total Depreciation & Amortization Reserve		$ (155,719,939)	$ (115,215,427)	$ (40,485,131)	$ (19,381)
54							
55		Net Plant in Service		$ 477,585,698	$ 343,173,001	$ 133,616,068	$ 796,629
56							
57		Customer Deposits	CUS	$ (6,619,573)	$ (6,619,573)	$ -	$ -
58							
59		Customer Advances	MAINS/SVCS	$ (20,846,446)	$ (15,362,655)	$ (5,483,791)	$ -
60							
61		Accumulated Deferred Income Taxes	TOTPLT	$ (62,025,073)	$ (44,893,925)	$ (17,051,229)	$ (79,919)
62							
63		Materials and Supplies	TOTPLT	$ 3,662,479	$ 2,650,913	$ 1,006,847	$ 4,719
64							
65		Prepayments	OPEXP	$ 2,208,255	$ 1,850,945	$ 331,373	$ 25,938
66							
67		Pension & FAS 106 Regulatory Asset	OPEXP	$ 21,599,188	$ 18,104,296	$ 3,241,192	$ 253,700
68							
69		DIMP Deferrals	OPEXP	$ 468,231	$ 392,469	$ 70,263	$ 5,500
70							

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CLASSIFIED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
71		Cash Working Capital	OPEXP	$ (4,325,667)	$ (3,625,746)	$ (649,113)	$ (50,808)
72							
73		Total Rate Base		$ 411,707,092	$ 295,669,725	$ 115,081,609	$ 955,758

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CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	850-66	Transmission Expenses	DEM	$ 877,863	$ -	$ 877,863	$ -
3	870	Operation Supervision & Engineering	DIS871-879	$ 533,907	$ 433,561	$ 85,457	$ 14,889
4	870	Odorization	COM	$ -	$ -	$ -	$ -
5	871	Distribution Load Dispatch	COM	$ 222,551	$ -	$ -	$ 222,551
6	874	Mains and Services Expenses	MAINS/SVCS	$ 3,414,676	$ 2,516,423	$ 898,252	$ -
7	874	Odorization	COM	$ 307	$ -	$ -	$ 307
8	875	Measuring & Reg. Station Expense - General	DEM	$ 313,024	$ -	$ 313,024	$ -
9	875	Odorization	COM	$ 50,467	$ -	$ -	$ 50,467
10	876	Meas. & Reg. Station Expense.- Industrial	DEM	$ 62,324	$ -	$ 62,324	$ -
11	877	Meas. & Regulating Station Exp.- City Gate	DEM	$ 3,725	$ -	$ 3,725	$ -
12	878	Meter and House Regulator Expenses	CUS	$ 3,853,222	$ 3,853,222	$ -	$ -
13	879	Customer Installation Expenses	CUS	$ 110,787	$ 110,787	$ -	$ -
14	880	Other Expenses	CUS	$ 1,057,947	$ 1,057,947	$ -	$ -
15	880	Odorization	COM	$ 51	$ -	$ -	$ 51
16	881	Rents	DIS871-879	$ (192,350)	$ (156,198)	$ (30,787)	$ (5,364)
17		Total Transmission & Distribution Oper. Exp.		$ 10,308,501	$ 7,815,741	$ 2,209,858	$ 282,901
18							
19		Distribution Maintenance Expenses					
20	885	Maintenance Supervision and Engineering	DIS887-893	$ -	$ -	$ -	$ -
21	886	Structures and Improvements	DIS887-893	$ 241,782	$ 131,897	$ 109,885	$ -
22	887	Maintenance of Mains	MAINS	$ 2,202,845	$ 1,332,060	$ 870,785	$ -
23	889	Maint. of Meas. & Reg. Sta. Equip.- General	DEM	$ 246,589	$ -	$ 246,589	$ -
24	889	Odorization	COM	$ 17,985	$ -	$ -	$ 17,985

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CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
25	890	Maint. of Meas. & Reg. Sta. Equip. - Industrial	DEM	$ 433,019	$ -	$ 433,019	$ -
26	891	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 20,124	$ -	$ 20,124	$ -
27	892	Maintenance of Services	CUS	$ 545,911	$ 545,911	$ -	$ -
28	893	Main. of Meters & House Regulators	CUS	$ 7,161	$ 7,161	$ -	$ -
29	894	Maintenance of Other Equipment	DIS887-893	$ -	$ -	$ -	$ -
30		Total Distribution Maintenance Expenses		$ 3,715,416	$ 2,017,029	$ 1,680,401	$ 17,985
31							
32		Total Operations & Maintenance Expenses		$ 14,023,916	$ 9,832,771	$ 3,890,260	$ 300,886
33							
34		Customer Accounts Expenses					
35	901	Supervision	CUS	$ 132,145	$ 132,145	$ -	$ -
36	902	Meter Reading Expense	CUS	$ 1,106,600	$ 1,106,600	$ -	$ -
37	903	Customer Accounting	CUS	$ 3,441,877	$ 3,441,877	$ -	$ -
38	904	Bad Debts (includes gross up)	CUS	$ 564,333	$ 564,333	$ -	$ -
39	905	Miscellaneous Customer Accounts Expenses	CUS	$ 279,972	$ 279,972	$ -	$ -
40		Total Customer Accounts Expenses		$ 5,524,928	$ 5,524,928	$ -	$ -
41							
42		Customer Service Expenses					
43	907	Supervision	CUS	$ -	$ -	$ -	$ -
44	908	Customer Assistance	CUS	$ 628,355	$ 628,355	$ -	$ -
45	909	Informational and Instructional Advertising	CUS	$ 79,798	$ 79,798	$ -	$ -
46		Total Customer Service Expenses		$ 708,154	$ 708,154	$ -	$

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CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
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UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
47							
48		Sales and Advertising Expenses					
49	912	Demonstrating and Selling	CUS	$ -	$ -	$ -	$ -
50	913	Advertising	CUS	$ 23,306	$ 23,306	$ -	$ -
51		Total Sales and Advertising Expenses		$ 23,306	$ 23,306	$ -	$ -
52							
53		Administrative & General Expenses					
54	921-32	Administrative & General Expenses	ADMINGEN	$ 22,491,930	$ 19,762,245	$ 2,528,176	$ 201,509
55		Total Administrative & General Expenses		$ 22,491,930	$ 19,762,245	$ 2,528,176	$ 201,509
56							
57		Depreciation and Amortization Expense					
58	301-303	Intangible Plant	PLT301-03	$ 32,190	$ 23,299	$ 8,849	$ 41
59	365	Land and Land Rights	DEM	$ 32	$ -	$ 32	$ -
60	366	Meas. and Reg. Station Structures	PLT366	$ 95	$ -	$ 95	$ -
61	367	Transmission Mains	PLT367	$ 213,908	$ -	$ 213,908	$ -
62	368	Compression Station Equipment	PLT368	$ -	$ -	$ -	$ -
63	369	Measuring and Reg. Station Equipment	PLT369	$ 43,750	$ -	$ 43,750	$ -
64	371	Other Equipment	PLT371	$ 1,201	$ -	$ 1,201	$ -
65	375	Structures and Improvements	PLT375	$ 703	$ 407	$ 296	$ 0
66	376	Mains	PLT376	$ 6,887,704	$ 4,164,994	$ 2,722,710	$ -
67	378	Meas. & Reg. Sta. Equipment - General	PLT378	$ 258,168	$ -	$ 258,168	$ -
68	378	Odorization Tank	COM	$ 13,347	$ -	$ -	$ 13,347
69	379	Meas. & Reg. Sta. Equipment - City Gate	PLT379	$ 23,028	$ -	$ 23,028	$ -
70	379	Odorization Tank	COM	$ 1,136	$ -	$ -	$ 1,136

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CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
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UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
71	380	Services	PLT380	$ 3,832,946	$ 3,832,946	$ -	$ -
72	381	Meters	PLT381	$ 2,111,908	$ 2,111,908	$ -	$ -
73	382	Meter Installations	PLT382	$ -	$ -	$ -	$ -
74	383	House Regulators	PLT383	$ 182,409	$ 182,409	$ -	$ -
75	385	Meas. & Reg. Sta. Equip. - Industrial	PLT385	$ 243,545	$ -	$ 243,545	$ -
76	385	Odorization Tank	COM	$ 1,024	$ -	$ -	$ 1,024
77	386	Other Property - Customer Premises	PLT386	$ 5,194	$ 5,194	$ -	$ -
78	387	Other Equipment		$ -	$ -	$ -	$ -
79	389-98	General Plant	GENDEP	$ 4,357,996	$ 3,806,022	$ 549,161	$ 2,813
80	4073	Pension & FAS 106 Amortization Expense	OPEXP	$ 319,295	$ 267,631	$ 47,914	$ 3,750
81		Total Depreciation and Amortization Expense		$ 18,529,579	$ 14,394,809	$ 4,112,658	$ 22,111
82							
83		Taxes Other Than Income					
84	408	Payroll and Other	OPEXP	$ 2,182,341	$ 1,829,224	$ 327,484	$ 25,633
85	408	Ad Valorem	TOTPLT	$ 3,694,134	$ 2,673,825	$ 1,015,549	$ 4,760
86	408	Revenue Related (includes gross up)	CUS	$ 132,095	$ 132,095	$ -	$ -
87		Total Taxes Other Than Income		$ 6,008,570	$ 4,635,143.61	$ 1,343,033.25	$ 30,393.23
88							
89	431	Interest on Customer Deposits	CUS	$ 127,096	$ 127,096	$ -	$ -
90							
91		Required Return	RB	$ 32,634,177	$ 23,436,415	$ 9,122,004	$ 75,759
92		Income Taxes	RB	$ 6,829,902	$ 4,904,932	$ 1,909,115	$ 15,855
93		Total Cost of Service Before Revenue Credits		$ 106,901,558	$ 83,349,799	$ 22,905,246	$ 646,513

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CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**CUS**	**Customer Factor**		**1.00000**	**0.00000**	**0.00000**
2							
3		**DEM**	**Demand Factor**		**0.00000**	**1.00000**	**0.00000**
4							
5		**COM**	**Commodity Factor**		**0.00000**	**0.00000**	**1.00000**
6							
7		**DEM-COM**	**Demand and Commodity Factor**		**0.00000**	**0.50000**	**0.50000**
8							
9			Total Transmission Plant	$ 14,754,342	$ -	$ 14,754,342	$ -
10			Total Distribution Plant	$ 548,183,452	$ 400,054,007	$ 147,374,612	$ 754,833
11			Total General Plant	$ 69,173,746	$ 57,470,130	$ 11,643,977	$ 59,639
12			Total Non-Intangible Plant	$ 632,111,540	$ 457,524,138	$ 173,772,931	$ 814,472
13		**NONINTPLT**	**Non-Intangible Plant Factor**	**1.00000**	**0.72380**	**0.27491**	**0.00129**
14							
15	376		Distribution Mains	$ 303,196,900	$ 183,343,142	$ 119,853,758	$ -
16	378		Meas. & Reg. Sta. Equip.- General	$ 12,264,948	$ -	$ 12,264,948	$ -
17	379		Meas. & Reg. Sta. Equip.- City Gate	$ 1,491,620	$ -	$ 1,421,467	$ 70,153
18			Total Accounts 376-379	$ 316,953,467	$ 183,343,142	$ 133,540,172	70,153
19		**DIS376-379**	**Accounts 376-379 Factor**	**1.00000**	**0.57845**	**0.42132**	**0.00022**
20							
21	376		Mains	$ 303,196,900	$ 183,343,142	$ 119,853,758	$ -
22		**MAINS**	**Distribution Mains Factor**	**1.00000**	**0.60470**	**0.39530**	**0.00000**
23							
24	376/380		Mains and Services	$ 455,620,004	$ 335,766,246	$ 119,853,758	$

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CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
25		**MAINS/SVCS**	**Mains and Services Factor**	**1.00000**	**0.73694**	**0.26306**	**0.00000**
26							
27	374-87		Total Distribution Plant	$ 548,183,452	$ 400,054,007	$ 147,374,612	$ 754,833
28		**DISPLT**	**Distribution Plant Factor**	**1.00000**	**0.72978**	**0.26884**	**0.00138**
29							
30			General Plant Reserve	$ (24,585,803)	$ (20,081,329)	$ (4,481,520)	$ (22,954)
31		**GENPLTRES**	**General Plant Reserve Factor**	**1.00000**	**0.81679**	**0.18228**	**0.00093**
32							
33			Total Plant	$ 633,305,637	$ 458,388,428	$ 174,101,199	$ 816,010
34		**TOTPLT**	**Total Plant Factor**	**1.00000**	**0.72380**	**0.27491**	**0.00129**
35							
36	374		Land & Land Rights	$ (7,410)	$ (4,286)	$ (3,122)	$ (2)
37	375		Structures and Improvements	$ (20,831)	$ (12,050)	$ (8,776)	$ (5)
38	376		Distribution Mains	$ (64,593,667)	$ (39,059,786)	$ (25,533,882)	$ -
39	378		Meas. & Reg. Station Equip.- General	$ (2,443,042)	$ -	$ (2,443,042)	$ -
40	379		Meas. & Reg. Station Equip.- City Gate	$ (389,414)	$ -	$ (389,414)	$ -
41	379		Odorization Tank	$ 5,304	$ -	$ -	$ 5,304
42	380		Services	$ (30,044,198)	$ (30,044,198)	$ -	$ -
43	381		Meters	$ (21,225,680)	$ (21,225,680)	$ -	$ -
44	382		Meter Installations	$ (5,776)	$ (5,776)	$ -	$ -
45	383		House Regulators	$ (3,434,323)	$ (3,434,323)	$ -	$ -
46	385		Meas. & Reg. Sta. Equipment - Industrial	$ (3,274,106)	$ -	$ (3,274,106)	$ -
47	386		Other Property - Customer Premises	$ (992,130)	$ (573,902)	$ (418,009)	$ (220)
48	378		Other Equipment	$ -			

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
49			Total Distribution Plant Reserve	$ (126,425,272)	$ (94,360,000)	$ (32,070,350)	$ 5,078
50		**DISPLTRES**	**Distribution Plant Reserve**	**1.00000**	**0.74637**	**0.25367**	**(0.00004)**
51							
52			Total Operations and Maintenance Expenses	$ 14,023,916	$ 9,832,771	$ 3,890,260	$ 300,886
53			Total Customer Accounts Expenses	$ 5,524,928	$ 5,524,928	$ -	$ -
54			Total Customer Service Expenses	$ 708,154	$ 708,154	$ -	$ -
55			Total Sales and Advertising Expenses	$ 23,306	$ 23,306	$ -	$ -
56			Administrative and General Expenses	$ 22,491,930	$ 19,762,245	$ 2,528,176	$ 201,509
57			Total Operating Expenses	$ 42,772,234	$ 35,851,403	$ 6,418,436	$ 502,395
58		**OPEXP**	**Operating Expense Factor**	**1.00000**	**0.83819**	**0.15006**	**0.01175**
59							
60	871		Distribution Load Dispatch	$ 222,551	$ -	$ -	$ 222,551
61	874		Mains and Services Expenses	$ 3,414,676	$ 2,516,423	$ 898,252	$ -
62	875		Measuring & Reg. Station Expense - General	$ 313,024	$ -	$ 313,024	$ -
63	876		Meas. & Reg. Station Expense.- Industrial	$ 62,324	$ -	$ 62,324	$ -
64	877		Meas. & Regulating Station Exp.- City Gate	$ 3,725	$ -	$ 3,725	$ -
65	878		Meter and House Regulator Expenses	$ 3,853,222	$ 3,853,222	$ -	$ -
66	879		Customer Installation Expenses	$ 110,787	$ 110,787	$ -	$ -
67			Total Accounts 871-879	$ 7,980,309	$ 6,480,432	$ 1,277,326	$ 222,551
68		**DIS871-879**	**Accounts 871-879 Factor**	**1.00000**	**0.81205**	**0.16006**	**0.02789**
69							
70	887		Maintenance of Mains	$ 2,202,845	$ 1,332,060	$ 870,785	$ -
71	889		Maint. of Meas. & Reg. Sta. Equip.- General	$ 246,589	$ -	$ 246,589	$
72	890		Maint. of Meas. & Reg. Sta. Equip. - Industrial	$ 433,019	$ -	$ 433,019	$

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CLASSIFICATION FACTORS

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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
73	891		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 20,124	$ -	$ 20,124	$ -
74	892		Maintenance of Services	$ 545,911	$ 545,911	$ -	$ -
75	893		Main. of Meters & House Regulators	$ 7,161	$ 7,161	$ -	$ -
76			Total Accounts 887-893	$ 3,455,649	$ 1,885,132	$ 1,570,517	$ -
77		**DIS887-893**	**Accounts 887-893 Factor**	**1.00000**	**0.54552**	**0.45448**	**0.00000**
78							
79			Total Operations and Maintenance Expenses	$ 14,023,916	$ 9,832,771	$ 3,890,260	$ 300,886
80			Total Customer Accounts Expenses	$ 5,524,928	$ 5,524,928	$ -	-
81			Total Customer Service Expenses	$ 708,154	$ 708,154	$ -	-
82			Total Sales and Advertising Expenses	$ 23,306	$ 23,306	$ -	$ -
83			Total Operating Exp. Without A&G Expenses	$ 20,280,303	$ 16,089,158	$ 3,890,260	$ 300,886
84		**NONAGOPEXP**	**Non-A&G Operating Expenses Factor**	**1.00000**	**0.79334**	**0.19182**	**0.01484**
85							
86	920-932		Administrative and General Expenses	$ 22,491,930	$ 19,762,245	$ 2,528,176	$ 201,509
87		**ADMINGEN**	**Administrative and General Expenses Factor**	**1.00000**	**0.87864**	**0.11240**	**0.00896**
88							
89	366		Meas. and Reg. Station Structures	$ 2,346	$ -	$ 2,346	$ -
90		**PLT366**	**Measuring and Reg. Station Structures Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
91							
92	367		Transmission Mains	$ 12,223,339	$ -	$ 12,223,339	$ -
93		**PLT367**	**Transmission Mains**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
94							
95	368		Compression Station Equipment	$ -	$ -	$ -	$ -
96		**PLT368**	**Compression Station Equipment Factor**	**0.00000**	**0.00000**	**0.00000**	**0.00000**

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CLASSIFICATION FACTORS

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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
97							
98	369		Measuring and Reg. Station Equipment	$ 2,390,734	$ -	$ 2,390,734	$ -
99		**PLT369**	**Measuring & Reg, Station Equipment Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
100							
101	371		Other Equipment	$ 45,840	$ -	$ 45,840	$ -
102		**PLT371**	**Other Equipment Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
103							
104	375		Structures and Improvements	$ 35,311	$ 20,426	$ 14,877	$ 8
105		**PLT375**	**Structures and Improvements Factor**	**1.00000**	**0.57845**	**0.42132**	**0.00022**
106							
107	376		Distribution Mains	$ 303,196,900	$ 183,343,142	$ 119,853,758	$ -
108		**PLT376**	**Distribution Mains Factor**	**1.00000**	**0.60470**	**0.39530**	**0.00000**
109							
110	378		Meas. & Reg. Sta. Equip.- General	$ 12,264,948	$ -	$ 12,264,948	$ -
111		**PLT378**	**Meas. & Reg. Station Equip. - General Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
112							
113	379		Meas. & Reg. Sta. Equip.- City Gate	$ 1,421,467	$ -	$ 1,421,467	$ -
114		**PLT379**	**Meas. & Reg. Station Equip. - City Gate Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
115							
116	380		Services	$ 152,423,104	$ 152,423,104	$ -	$ -
117		**PLT380**	**Services Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
118							
119	381		Meters	$ 53,737,506	$ 53,737,506	$ -	$ -
120		**PLT381**	**Meters Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**

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CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
121							
122	382		Meter Installations	$ (459,739)	$ (459,739)	$ -	$ -
123		**PLT382**	**Meter Installations Factor**	**1.00000**	**1.00000**	**0.00000**	**0.0000**
124							
125	383		House Regulators	$ 7,382,713	$ 7,382,713	$ -	$ -
126		**PLT383**	**House Regulators Factor**	**1.00000**	**1.00000**	**0.00000**	**0.0000**
127							
128	385		Meas. & Reg. Sta. Equipment - Industrial	$ 11,374,459	$ -	$ 11,374,459	$ -
129		**PLT385**	**Meas. & Reg. Sta. Equip.-Industrial Factor**	**1.00000**	**0.00000**	**1.00000**	**0.0000**
130							
131	386		Other Property - Customer Premises	$ 249,867	$ 249,867	$ -	$ -
132		**PLT386**	**Other Property-Customer Premises Factor**	**1.00000**	**1.00000**	**0.00000**	**0.0000**
133							
134	301-03		Intangible Plant	$ 1,194,097	$ 864,291	$ 328,268	$ 1,539
135		**PLT301-03**	**Intangible Plant**	**1.00000**	**0.72380**	**0.27491**	**0.00129**
136							
137	389-98		General Plant Depreciation Expense	$ 4,357,996	$ 3,806,022	$ 549,161	$ 2,813
138		**GENDEP**	**General Plant Depreciation Expense Factor**	**1.00000**	**0.87334**	**0.12601**	**0.00065**
139							
140			Rate Base	$ 411,707,092	$ 295,669,725	$ 115,081,609	$ 955,758
141		**RB**	**Rate Base Factor**	**1.00000**	**0.71816**	**0.27952**	**0.00232**

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ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	301-303	**Intangible Plant**								
2		Customer	CUS	$ 864,291	$ 819,516	$ 41,173	$ 177	$ 3,118	$ 283	$ 23
3		Demand	DEM	$ 328,268	$ 240,715	$ 59,211	$ 6,165	$ 18,604	$ 2,947	$ 626
4		Commodity	COM	$ 1,539	$ 823	$ 506	$ 58	$ 127	$ 12	$ 12
		Total Intangible Plant		$ 1,194,097	$ 1,061,054	$ 100,890	$ 6,401	$ 21,849	$ 3,242	$ 661
5	365-371	**Transmission Plant**								
6		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7		Demand	DEM	$ 14,754,342	$ 10,819,199	$ 2,661,292	$ 277,114	$ 836,175	$ 132,439	$ 28,123
8		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Total Transmission Plant		$ 14,754,342	$ 10,819,199	$ 2,661,292	$ 277,114	$ 836,175	$ 132,439	$ 28,123
10		**Distribution Plant**								
11	374	**Land & Land Rights**								
12		Customer	CUS	$ 3,356,990	$ 3,183,082	$ 159,921	$ 687	$ 12,110	$ 1,101	$ 89
13		Demand	DEM	$ 2,445,104	$ 1,792,968	$ 441,032	$ 45,924	$ 138,572	$ 21,948	$ 4,661
14		Commodity	COM	$ 1,284	$ 687	$ 423	$ 49	$ 106	$ 10	$ 10
15		Total Land & Land Rights		$ 5,803,378	$ 4,976,737	$ 601,376	$ 46,659	$ 150,788	$ 23,059	$ 4,759
16	375	**Structures and Improvements**								
17		Customer	CUS	$ 20,426	$ 19,367	$ 973	$ 4	$ 74	$ 7	$ 1
18		Demand	DEM	$ 14,877	$ 10,909	$ 2,683	$ 279	$ 843	$ 134	$ 28
19		Commodity	COM	$ 8	$ 4	$ 3	$ 0	$ 1	$ 0	$ 0
20		Total Structures and Improvements		$ 35,311	$ 30,281	$ 3,659	$ 284	$ 917	$ 140	$ 29
21	376	**Distribution Mains**								
22		Customer	CUS	$ 183,343,142	$ 173,845,090	$ 8,734,147	$ 37,526	$ 661,408	$ 60,134	$ 4,835
23		Demand	DEM	$ 119,853,758	$ 87,887,462	$ 21,618,438	$ 2,251,076	$ 6,792,492	$ 1,075,838	$ 228,452
24		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Total Distribution Mains		$ 303,196,900	$ 261,732,553	$ 30,352,585	$ 2,288,603	$ 7,453,900	$ 1,135,972	$ 233,287
26	378	**Meas. & Reg. Sta. Equip. - General**								
27		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	DEM	$ 12,264,948	$ 8,993,753	$ 2,212,271	$ 230,359	$ 695,093	$ 110,093	$ 23,378
29		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$

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ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
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CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
30		Total Meas. & Reg. Sta. Equip.- Gen.		$ 12,264,948	$ 8,993,753	$ 2,212,271	$ 230,359	$ 695,093	$ 110,093	$ 23,378
31	378	**Odorization Tank**								
32		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Commodity	COM	$ 635,549	$ 339,846	$ 209,097	$ 24,118	$ 52,535	$ 4,925	$ 5,029
35		Total Odorization Tank		$ 635,549	$ 339,846	$ 209,097	$ 24,118	$ 52,535	$ 4,925	$ 5,029
36	379	**Meas. & Reg. Station - City Gate**								
37		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Demand	DEM	$ 1,421,467	$ 1,042,346	$ 256,395	$ 26,698	$ 80,559	$ 12,759	$ 2,709
39		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Total Meas. & Reg. Equip.-City Gate		$ 1,421,467	$ 1,042,346	$ 256,395	$ 26,698	$ 80,559	$ 12,759	$ 2,709
41	379	**Odorization Tank**								
42		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Commodity	COM	$ 70,153	$ 37,513	$ 23,081	$ 2,662	$ 5,799	$ 544	$ 555
45		Total Odorization Tank		$ 70,153	$ 37,513	$ 23,081	$ 2,662	$ 5,799	$ 544	$ 555
46	380	**Services**								
47		Customer	SERCUS	$ 152,423,104	$ 143,689,331	$ 7,947,602	$ 43,747	$ 668,207	$ 69,125	$ 5,093
48		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50		Total Services		$ 152,423,104	$ 143,689,331	$ 7,947,602	$ 43,747	$ 668,207	$ 69,125	$ 5,093
51	381	**Meters**								
52		Customer	METCUS	$ 53,737,506	$ 48,481,914	$ 4,628,759	$ 77,106	$ 463,653	$ 76,482	$ 9,592
53		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Total Meters		$ 53,737,506	$ 48,481,914	$ 4,628,759	$ 77,106	$ 463,653	$ 76,482	$ 9,592
56	382	**Meter Installations**								
57		Customer	METCUS	$ (459,739)	$ (414,776)	$ (39,600)	$ (660)	$ (3,967)	$ (654)	$ (82)
58		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
60		Total Meter Installations		$ (459,739)	$ (414,776)	$ (39,600)	$ (660)	$ (3,967)	$ (654)	$ (82)
61	383	**House Regulators**								
62		Customer	REGCUS	$ 7,382,713	$ 6,414,272	$ 849,337	$ 14,586	$ 87,026	$ 15,718	$ 1,774
63		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65		Total House Regulators		$ 7,382,713	$ 6,414,272	$ 849,337	$ 14,586	$ 87,026	$ 15,718	$ 1,774
66	385	**Meas. & Reg. Sta. Equip.- Ind.**								
67		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
68		Demand	NRDEM	$ 11,374,459	$ -	$ 7,692,416	$ 800,993	$ 2,416,949	$ 382,812	$ 81,289
69		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70		Total Meas. & Reg. Sta. Equip.- Ind.		$ 11,374,459	$ -	$ 7,692,416	$ 800,993	$ 2,416,949	$ 382,812	$ 81,289
71	385	**Odorization Tank**								
72		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74		Commodity	COM	$ 47,838	$ 25,580	$ 15,739	$ 1,815	$ 3,954	$ 371	$ 378
75		Total Odorization Tank		$ 47,838	$ 25,580	$ 15,739	$ 1,815	$ 3,954	$ 371	$ 378
76	386	**Other Prop.-Customer Premises**								
77		Customer	CUS	$ 249,867	$ 236,922	$ 11,903	$ 51	$ 901	$ 82	$ 7
78		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80		Total Other Prop.- Cust. Premises		$ 249,867	$ 236,922	$ 11,903	$ 51	$ 901	$ 82	$ 7
81	387	**Other Equipment**								
82		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
83		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
86		**Total Distribution Plant**								
87		Customer		$ 400,054,007	$ 375,455,203	$ 22,293,042	$ 173,047	$ 1,889,412	$ 221,995	$ 21,308
88		Demand		$ 147,374,612	$ 99,727,439	$ 32,223,235	$ 3,355,328	$ 10,124,509	$ 1,603,584	$ 340,517
89		Commodity		$ 754,833	$ 403,630	$ 248,341	$ 28,645	$ 62,395	$ 5,849	$ 5,97[illegible]

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ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
90		Total Distribution Plant		$ 548,183,452	$ 475,586,272	$ 54,764,619	$ 3,557,021	$ 12,076,316	$ 1,831,428	$ 367,797
91		**Total General Plant**								
92		Customer	CUS	$ 57,470,130	$ 54,492,903	$ 2,737,777	$ 11,763	$ 207,323	$ 18,849	$ 1,516
93		Demand	DEM	$ 11,643,977	$ 8,538,402	$ 2,100,265	$ 218,696	$ 659,901	$ 104,519	$ 22,194
94		Commodity	COM	$ 59,639	$ 31,891	$ 19,621	$ 2,263	$ 4,930	$ 462	$ 472
95		Total General Plant		$ 69,173,746	$ 63,063,196	$ 4,857,662	$ 232,722	$ 872,154	$ 123,831	$ 24,182
96		**Total Plant in Service**								
97		Customer		$ 458,388,428	$ 430,767,622	$ 25,071,992	$ 184,987	$ 2,099,853	$ 241,128	$ 22,846
98		Demand		$ 174,101,199	$ 119,325,755	$ 37,044,002	$ 3,857,303	$ 11,639,189	$ 1,843,489	$ 391,460
99		Commodity		$ 816,010	$ 436,344	$ 268,469	$ 30,966	$ 67,452	$ 6,323	$ 6,456
100		Total Plant in Service		$ 633,305,637	$ 550,529,721	$ 62,384,463	$ 4,073,257	$ 13,806,494	$ 2,090,940	$ 420,763
101		**Depreciation & Amort. Reserve**								
102		**Intangible Plant**								
103		Customer	CUS	$ (843,419)	$ (799,726)	$ (40,179)	$ (173)	$ (3,043)	$ (277)	$ (22)
104		Demand	DEM	$ (320,340)	$ (234,902)	$ (57,781)	$ (6,017)	$ (18,155)	$ (2,875)	$ (611)
105		Commodity	COM	$ (1,501)	$ (803)	$ (494)	$ (57)	$ (124)	$ (12)	$ (12)
106		Total Intangible Plant		$ (1,165,261)	$ (1,035,431)	$ (98,454)	$ (6,246)	$ (21,321)	$ (3,164)	$ (645)
107		**Transmission Plant**								
108		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
109		Demand	DEM	$ (3,636,481)	$ (2,666,592)	$ (655,925)	$ (68,300)	$ (206,091)	$ (32,642)	$ (6,931)
110		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111		Total Transmission Plant		$ (3,636,481)	$ (2,666,592)	$ (655,925)	$ (68,300)	$ (206,091)	$ (32,642)	$ (6,931)
112		**Distribution Plant**								
113		Customer	DISPLTCUS	$ (94,290,679)	$ (88,492,867)	$ (5,254,356)	$ (40,786)	$ (445,325)	$ (52,323)	$ (5,022)
114		Demand	DISPLTDEM	$ (32,046,790)	$ (21,685,854)	$ (7,006,982)	$ (729,620)	$ (2,201,587)	$ (348,701)	$ (74,046)
115		Commodity	COM	$ 5,074	$ 2,713	$ 1,669	$ 193	$ 419	$ 39	$ 40
116		Total Distribution Plant		$ (126,332,395)	$ (110,176,007)	$ (12,259,668)	$ (770,214)	$ (2,646,492)	$ (400,985)	$ (79,028)
117		**General Plant**								
118		Customer	CUS	$ (20,081,329)	$ (19,041,020)	$ (956,639)	$ (4,110)	$ (72,443)	$ (6,586)	$ (53[illegible])
119		Demand	DEM	$ (4,481,520)	$ (3,286,250)	$ (808,347)	$ (84,171)	$ (253,982)	$ (40,227)	$ (8,54[illegible])

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ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
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UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
120		Commodity	COM	$ (22,954)	$ (12,274)	$ (7,552)	$ (871)	$ (1,897)	$ (178)	$ (182)
121		Total General Plant		$ (24,585,803)	$ (22,339,544)	$ (1,772,539)	$ (89,153)	$ (328,322)	$ (46,992)	$ (9,253)
122		**Total Depr. & Amort. Reserve**								
123		Customer		$ (115,215,427)	$ (108,333,613)	$ (6,251,174)	$ (45,069)	$ (520,811)	$ (59,186)	$ (5,574)
124		Demand		$ (40,485,131)	$ (27,873,598)	$ (8,529,035)	$ (888,108)	$ (2,679,814)	$ (424,446)	$ (90,130)
125		Commodity		$ (19,381)	$ (10,364)	$ (6,376)	$ (735)	$ (1,602)	$ (150)	$ (153)
126		Total Depr. & Amortization Reserve		$ (155,719,939)	$ (136,217,574)	$ (14,786,585)	$ (933,913)	$ (3,202,227)	$ (483,782)	$ (95,857)
127		**Net Plant in Service**								
128		Customer		$ 343,173,001	$ 322,434,009	$ 18,820,818	$ 139,918	$ 1,579,042	$ 181,942	$ 17,272
129		Demand		$ 133,616,068	$ 91,452,157	$ 28,514,967	$ 2,969,195	$ 8,959,375	$ 1,419,043	$ 301,330
130		Commodity		$ 796,629	$ 425,980	$ 262,092	$ 30,231	$ 65,850	$ 6,173	$ 6,303
131		Total Net Plant in Service		$ 477,585,698	$ 414,312,147	$ 47,597,878	$ 3,139,344	$ 10,604,267	$ 1,607,157	$ 324,905
132		**Customer Deposits**								
133		Customer	DEPCUS	$ (6,619,573)	$ (3,824,975)	$ (2,753,338)	$ (33,266)	$ (7,173)	$ (822)	$ -
134		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
135		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136		Total Customer Deposits		$ (6,619,573)	$ (3,824,975)	$ (2,753,338)	$ (33,266)	$ (7,173)	$ (822)	$ -
137		**Customer Advances**								
138		Customer	MSCUS	$ (15,362,655)	$ (14,528,476)	$ (763,257)	$ (3,719)	$ (60,835)	$ (5,914)	$ (454)
139		Demand	DEM	$ (5,483,791)	$ (4,021,205)	$ (989,130)	$ (102,996)	$ (310,784)	$ (49,224)	$ (10,453)
140		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
141		Total Customer Advances		$ (20,846,446)	$ (18,549,681)	$ (1,752,387)	$ (106,714)	$ (371,619)	$ (55,138)	$ (10,907)
142		**Accum. Deferred Income Taxes**								
143		Customer	TPLTCUS	$ (44,893,925)	$ (42,188,782)	$ (2,455,516)	$ (18,117)	$ (205,657)	$ (23,616)	$ (2,238)
144		Demand	TPLTDEM	$ (17,051,229)	$ (11,686,598)	$ (3,628,038)	$ (377,779)	$ (1,139,926)	$ (180,549)	$ (38,339)
145		Commodity	COM	$ (79,919)	$ (42,735)	$ (26,293)	$ (3,033)	$ (6,606)	$ (619)	$ (632)
146		Total Accum. Deferred Inc. Taxes		$ (62,025,073)	$ (53,918,115)	$ (6,109,848)	$ (398,929)	$ (1,352,189)	$ (204,784)	$ (41,209)
147		**Materials and Supplies**								
148		Customer	TPLTCUS	$ 2,650,913	$ 2,491,179	$ 144,994	$ 1,070	$ 12,144	$ 1,394	$ 13[illegible]
149		Demand	TPLTDEM	$ 1,006,847	$ 690,075	$ 214,230	$ 22,307	$ 67,311	$ 10,661	$ 2,26[illegible]

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ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
150		Commodity	COM	$ 4,719	$ 2,523	$ 1,553	$ 179	$ 390	$ 37	$ 37
151		Total Materials and Supplies		$ 3,662,479	$ 3,183,777	$ 360,777	$ 23,556	$ 79,845	$ 12,092	$ 2,433
152		**Prepayments**								
153		Customer	OPEXPCUS	$ 1,850,945	$ 1,730,570	$ 108,705	$ 1,095	$ 9,236	$ 1,209	$ 130
154		Demand	OPEXPDEM	$ 331,373	$ 218,350	$ 76,436	$ 7,959	$ 24,016	$ 3,804	$ 808
155		Commodity	COM	$ 25,938	$ 13,870	$ 8,534	$ 984	$ 2,144	$ 201	$ 205
156		Total Prepayments		$ 2,208,255	$ 1,962,790	$ 193,674	$ 10,038	$ 35,397	$ 5,214	$ 1,143
157		**Pension & FAS 106 Reg. Asset**								
158		Customer	OPEXPCUS	$ 18,104,296	$ 16,926,897	$ 1,063,251	$ 10,709	$ 90,343	$ 11,824	$ 1,271
159		Demand	OPEXPDEM	$ 3,241,192	$ 2,135,708	$ 747,626	$ 77,848	$ 234,903	$ 37,205	$ 7,900
160		Commodity	COM	$ 253,700	$ 135,661	$ 83,468	$ 9,628	$ 20,971	$ 1,966	$ 2,007
161		Total Pen. & FAS 106 Reg. Asset		$ 21,599,188	$ 19,198,266	$ 1,894,345	$ 98,185	$ 346,217	$ 50,995	$ 11,179
162		**DIMP Deferrals**								
163		Customer	TPLTCUS	$ 392,469	$ 368,820	$ 21,466	$ 158	$ 1,798	$ 206	$ 20
164		Demand	TPLTDEM	$ 70,263	$ 48,157	$ 14,950	$ 1,557	$ 4,697	$ 744	$ 158
165		Commodity	COM	$ 5,500	$ 2,941	$ 1,809	$ 209	$ 455	$ 43	$ 44
166		Total DIMP Deferrals		$ 468,231	$ 419,918	$ 38,226	$ 1,924	$ 6,950	$ 993	$ 221
167		**Cash Working Capital**								
168		Customer	OPEXPCUS	$ (3,625,746)	$ (3,389,948)	$ (212,937)	$ (2,145)	$ (18,093)	$ (2,368)	$ (255)
169		Demand	OPEXPDEM	$ (649,113)	$ (427,718)	$ (149,727)	$ (15,591)	$ (47,044)	$ (7,451)	$ (1,582)
170		Commodity	COM	$ (50,808)	$ (27,169)	$ (16,716)	$ (1,928)	$ (4,200)	$ (394)	$ (402)
171		Total Cash Working Capital		$ (4,325,667)	$ (3,844,835)	$ (379,380)	$ (19,664)	$ (69,337)	$ (10,213)	$ (2,239)
172		**Total Rate Base**								
173		Customer		$ 295,669,725	$ 280,019,293	$ 13,974,187	$ 95,704	$ 1,400,806	$ 163,856	$ 15,879
174		Demand		$ 115,081,609	$ 78,408,926	$ 24,801,313	$ 2,582,501	$ 7,792,548	$ 1,234,233	$ 262,087
175		Commodity		$ 955,758	$ 511,071	$ 314,446	$ 36,270	$ 79,003	$ 7,406	$ 7,562
176		Total Rate Base		$ 411,707,092	$ 358,939,291	$ 39,089,946	$ 2,714,475	$ 9,272,358	$ 1,405,495	$ 285,527

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1		**Transmission and Distribution Operating Expense**								
2	850-66	**Transmission Expense**								
3		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	DEM	$ 877,863	$ 643,727	$ 158,343	$ 16,488	$ 49,751	$ 7,880	$ 1,673
5		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6		Total Transmission Expense		$ 877,863	$ 643,727	$ 158,343	$ 16,488	$ 49,751	$ 7,880	$ 1,673
7	870	**Supervision and Engineering**								
8		Customer	871-879CUS	$ 433,561	$ 396,968	$ 32,520	$ 446	$ 3,098	$ 474	$ 55
9		Demand	DEM	$ 85,457	$ 62,665	$ 15,414	$ 1,605	$ 4,843	$ 767	$ 163
10		Commodity	COM	$ 14,889	$ 7,962	$ 4,899	$ 565	$ 1,231	$ 115	$ 118
11		Total Supervision & Engineering		$ 533,907	$ 467,594	$ 52,833	$ 2,616	$ 9,172	$ 1,357	$ 336
12	871	**Distribution Load Dispatch**								
13		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15		Commodity	COM	$ 222,551	$ 119,005	$ 73,220	$ 8,445	$ 18,396	$ 1,724	$ 1,761
16		Total Distribution Load Dispatch		$ 222,551	$ 119,005	$ 73,220	$ 8,445	$ 18,396	$ 1,724	$ 1,761
17	874	**Mains & Services**								
18		Customer	MSCUS	$ 2,516,423	$ 2,379,784	$ 125,023	$ 609	$ 9,965	$ 969	$ 74
19		Demand	DEM	$ 898,252	$ 658,679	$ 162,021	$ 16,871	$ 50,907	$ 8,063	$ 1,712
20		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Total Mains & Services		$ 3,414,676	$ 3,038,463	$ 287,043	$ 17,480	$ 60,872	$ 9,032	$ 1,787
22	874	**Odorization**								
23		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Commodity	COM	$ 307	$ 164	$ 101	$ 12	$ 25	$ 2	$ 2
26		Total Odorization		$ 307	$ 164	$ 101	$ 12	$ 25	$ 2	$ 2
27	875	**Meas. & Reg. Station - General**								
28		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29		Demand	DEM	$ 313,024	$ 229,537	$ 56,461	$ 5,879	$ 17,740	$ 2,810	$ 597
30		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31		Total Meas. & Reg. Station - General		$ 313,024	$ 229,537	$ 56,461	$ 5,879	$ 17,740	$ 2,810	$ 597
32	875	**Odorization**								
33		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
35		Commodity	COM	$ 50,467	$ 26,986	$ 16,604	$ 1,915	$ 4,172	$ 391	$ 399
36		Total Odorization		$ 50,467	$ 26,986	$ 16,604	$ 1,915	$ 4,172	$ 391	$ 399
37	876	**Meas. & Reg. Stat. - Industrial**								
38		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Demand	NRDEM	$ 62,324	$ -	$ 42,149	$ 4,389	$ 13,243	$ 2,098	$ 445
40		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Total Meas. & Reg. Stat. - Industrial		$ 62,324	$ -	$ 42,149	$ 4,389	$ 13,243	$ 2,098	$ 445
42	877	**Meas. & Reg. Stat.- City Gate**								
43		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Demand	DEM	$ 3,725	$ 2,732	$ 672	$ 70	$ 211	$ 33	$ 7
45		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Total Meas. & Reg. Stat. - City Gate		$ 3,725	$ 2,732	$ 672	$ 70	$ 211	$ 33	$ 7
47	878	**Meter & House Reg. Expense**								
48		Customer	MTRGCUS	$ 3,853,222	$ 3,453,739	$ 351,506	$ 5,896	$ 35,389	$ 5,963	$ 730
49		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51		Total Meter & House Reg. Expense		$ 3,853,222	$ 3,453,739	$ 351,506	$ 5,896	$ 35,389	$ 5,963	$ 730
52	879	**Customer Installation Expense**								
53		Customer	METCUS	$ 110,787	$ 99,952	$ 9,543	$ 159	$ 956	$ 158	$ 20
54		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56		Total Customer Install. Expense		$ 110,787	$ 99,952	$ 9,543	$ 159	$ 956	$ 158	$ 20
57	880	**Other Expenses**								
58		Customer	871-879CUS	$ 1,057,947	$ 968,655	$ 79,352	$ 1,088	$ 7,560	$ 1,157	$ 134
59		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61		Total Other Expenses		$ 1,057,947	$ 968,655	$ 79,352	$ 1,088	$ 7,560	$ 1,157	$ 134
62	880	**Odorization**								
63		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65		Commodity	COM	$ 51	$ 27	$ 17	$ 2	$ 4	$ 0	$ 0
66		Total Odorization		$ 51	$ 27	$ 17	$ 2	$ 4	$ 0	$ 0
67	881	**Rents**								
68		Customer	871-879CUS	$ (156,198)	$ (143,015)	$ (11,716)	$ (161)	$ (1,116)	$ (171)	$ (20)

ALLOCATED COST OF SERVICE

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UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
69		Demand	DEM	$ (30,787)	$ (22,576)	$ (5,553)	$ (578)	$ (1,745)	$ (276)	$ (59)
70		Commodity	COM	$ (5,364)	$ (2,868)	$ (1,765)	$ (204)	$ (443)	$ (42)	$ (42)
71		Total Rents		$ (192,350)	$ (168,459)	$ (19,034)	$ (942)	$ (3,304)	$ (489)	$ (121)
72		**Total Distr. & Trans. Op. Expense**								
73		Customer		$ 7,815,741	$ 7,156,082	$ 586,228	$ 8,037	$ 55,852	$ 8,550	$ 994
74		Demand		$ 2,209,858	$ 1,574,764	$ 429,507	$ 44,724	$ 134,951	$ 21,374	$ 4,539
75		Commodity		$ 282,901	$ 151,275	$ 93,075	$ 10,736	$ 23,385	$ 2,192	$ 2,238
76		Total Distr. & Trans. Operations Exp.		$ 10,308,501	$ 8,882,121	$ 1,108,810	$ 63,496	$ 214,187	$ 32,116	$ 7,771
77		**Distribution Maintenance Expenses**								
78	886	**Supervision and Engineering**								
79		Customer	887-893CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80		Demand	887-893DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82		Total Supervision and Engineering		$ -	$ -	$ -	$ -	$ -	$ -	$ -
83	886	**Structures and Improvements**								
84		Customer	887-893CUS	$ 131,897	$ 124,828	$ 6,477	$ 31	$ 508	$ 49	$ 4
85		Demand	887-893DEM	$ 109,885	$ 58,361	$ 34,845	$ 3,628	$ 10,948	$ 1,734	$ 368
86		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87		Total Structures and Improvements		$ 241,782	$ 183,189	$ 41,322	$ 3,659	$ 11,457	$ 1,783	$ 372
88	887	**Mains**								
89		Customer	CUS	$ 1,332,060	$ 1,263,053	$ 63,457	$ 273	$ 4,805	$ 437	$ 35
90		Demand	DEM	$ 870,785	$ 638,537	$ 157,066	$ 16,355	$ 49,350	$ 7,816	$ 1,660
91		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92		Total Mains		$ 2,202,845	$ 1,901,590	$ 220,523	$ 16,628	$ 54,156	$ 8,253	$ 1,695
93	889	**Meas. & Reg. Sta. Equip. - General**								
94		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95		Demand	DEM	$ 246,589	$ 180,821	$ 44,478	$ 4,631	$ 13,975	$ 2,213	$ 470
96		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97		Total Meas. & Reg. Sta. Equip. - Gen.		$ 246,589	$ 180,821	$ 44,478	$ 4,631	$ 13,975	$ 2,213	$ 470
98	889	**Odorization**								
99		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
100		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
101		Commodity	COM	$ 17,985	$ 9,617	$ 5,917	$ 682	$ 1,487	$ 139	$ 142
102		Total Odorization		$ 17,985	$ 9,617	$ 5,917	$ 682	$ 1,487	$ 139	$ 142

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
103	890	**Meas. & Reg. Sta. Equip. - Industrial**								
104		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
105		Demand	NRDEM	$ 433,019	$ -	$ 292,846	$ 30,493	$ 92,012	$ 14,573	$ 3,095
106		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
107		Total Meas. & Reg. Sta. Eq.- Industrial		$ 433,019	$ -	$ 292,846	$ 30,493	$ 92,012	$ 14,573	$ 3,095
108	891	**Meas. & Reg. Sta. Eq.- City Gate**								
109		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110		Demand	DEM	$ 20,124	$ 14,757	$ 3,630	$ 378	$ 1,141	$ 181	$ 38
111		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
112		Total Meas. & Reg. Sta. Eq.- City Gate		$ 20,124	$ 14,757	$ 3,630	$ 378	$ 1,141	$ 181	$ 38
113	892	**Services**								
114		Customer	SERCUS	$ 545,911	$ 514,631	$ 28,465	$ 157	$ 2,393	$ 248	$ 18
115		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117		Total Services		$ 545,911	$ 514,631	$ 28,465	$ 157	$ 2,393	$ 248	$ 18
118	893	**Meters & House Regulators**								
119		Customer	MTRGCUS	$ 7,161	$ 6,419	$ 653	$ 11	$ 66	$ 11	$ 1
120		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122		Total Meters & House Regulators		$ 7,161	$ 6,419	$ 653	$ 11	$ 66	$ 11	$ 1
123	894	**Other Equipment**								
124		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
125		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
126		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
127		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
128		**Total Distr. Maintenance Expense**								
129		Customer		$ 2,017,029	$ 1,908,931	$ 99,052	$ 471	$ 7,773	$ 744	$ 59
130		Demand		$ 1,680,401	$ 892,476	$ 532,865	$ 55,486	$ 167,426	$ 26,518	$ 5,631
131		Commodity		$ 17,985	$ 9,617	$ 5,917	$ 682	$ 1,487	$ 139	$ 142
132		Total Distr. Maintenance Expense		$ 3,715,416	$ 2,811,023	$ 637,834	$ 56,640	$ 176,685	$ 27,402	$ 5,832
133		**Total Oper. & Maint. Expense**								
134		Customer		$ 9,832,771	$ 9,065,013	$ 685,280	$ 8,508	$ 63,624	$ 9,294	$ 1,052
135		Demand		$ 3,890,260	$ 2,467,239	$ 962,372	$ 100,210	$ 302,376	$ 47,892	$ 10,170
136		Commodity		$ 300,886	$ 160,892	$ 98,992	$ 11,418	$ 24,871	$ 2,331	$ 2,381

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
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UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
137		Total Operations & Maint. Expense		$ 14,023,916	$ 11,693,144	$ 1,746,644	$ 120,135	$ 390,872	$ 59,518	$ 13,603
138		**Customer Accounts Expense**								
139	901	**Supervision**								
140		Customer	902-904CUS	$ 132,145	$ 125,491	$ 6,138	$ 65	$ 395	$ 49	$ 6
141		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
142		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
143		Total Supervision		$ 132,145	$ 125,491	$ 6,138	$ 65	$ 395	$ 49	$ 6
144	902	**Meter Reading Expense**								
145		Customer	METCUS	$ 1,106,600	$ 998,374	$ 95,319	$ 1,588	$ 9,548	$ 1,575	$ 198
146		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
147		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148		Total Meter Reading Expense		$ 1,106,600	$ 998,374	$ 95,319	$ 1,588	$ 9,548	$ 1,575	$ 198
149	903	**Customer Accounting**								
150		Customer	903CUS	$ 3,441,877	$ 3,317,780	$ 118,375	$ 231	$ 5,047	$ 414	$ 30
151		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
153		Total Customer Accounting		$ 3,441,877	$ 3,317,780	$ 118,375	$ 231	$ 5,047	$ 414	$ 30
154	904	**Bad Debt Expense**								
155		Customer	904CUS	$ 564,333	$ 539,228	$ 23,804	$ 694	$ 694	$ (86)	$ -
156		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
157		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
158		Total Bad Debt Expense		$ 564,333	$ 539,228	$ 23,804	$ 694	$ 694	$ (86)	$ -
159	905	**Miscellaneous Customer Accounts**								
160		Customer	902-904CUS	$ 279,972	$ 265,876	$ 13,005	$ 138	$ 837	$ 104	$ 12
161		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
162		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
163		Total Misc. Customer Accounts		$ 279,972	$ 265,876	$ 13,005	$ 138	$ 837	$ 104	$ 12
164	907-910	**Customer Service Expense**								
165		Customer	CUS	$ 708,154	$ 671,468	$ 33,735	$ 145	$ 2,555	$ 232	$ 19
166		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
167		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
168		Total Customer Service Expense		$ 708,154	$ 671,468	$ 33,735	$ 145	$ 2,555	$ 232	$ 19
169		**Sales and Advertising Expense**								
170	912	**Demonstrating and Selling**								

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
171		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
172		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
174		Total Demon. and Selling Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -
175	913	**Advertising**								
176		Customer	CUS	$ 23,306	$ 22,098	$ 1,110	$ 5	$ 84	$ 8	$ 1
177		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
178		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179		Total Advertising		$ 23,306	$ 22,098	$ 1,110	$ 5	$ 84	$ 8	$ 1
180		**Administrative & General Exp.**								
181	921-32	**Administrative & General Exp.**								
182		Customer	OPEXPCUS	$ 19,762,245	$ 18,477,023	$ 1,160,621	$ 11,690	$ 98,617	$ 12,907	$ 1,388
183		Demand	OPEXPDEM	$ 2,528,176	$ 1,665,883	$ 583,159	$ 60,723	$ 183,228	$ 29,021	$ 6,162
184		Commodity	COM	$ 201,509	$ 107,753	$ 66,297	$ 7,647	$ 16,657	$ 1,561	$ 1,594
185		Total Administrative & General Exp.		$ 22,491,930	$ 20,250,658	$ 1,810,077	$ 80,060	$ 298,501	$ 43,489	$ 9,145
186		**Depreciation & Amort. Expense**								
187	301-03	**Intangible Plant**								
188		Customer	CUS	$ 23,299	$ 22,092	$ 1,110	$ 5	$ 84	$ 8	$ 1
189		Demand	DEM	$ 8,849	$ 6,489	$ 1,596	$ 166	$ 502	$ 79	$ 17
190		Commodity	COM	$ 41	$ 22	$ 14	$ 2	$ 3	$ 0	$ 0
191		Total Intangible Plant		$ 32,190	$ 28,603	$ 2,720	$ 173	$ 589	$ 87	$ 18
192	365	**Land and Land Rights**								
193		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
194		Demand	DEM	$ 32	$ 23	$ 6	$ 1	$ 2	$ 0	$ 0
195		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
196		Total Land and Land Rights		$ 32	$ 23	$ 6	$ 1	$ 2	$ 0	$ 0
197	366	**Meas. and Reg. Station Structures**								
198		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
199		Demand	DEM	$ 95	$ 69	$ 17	$ 2	$ 5	$ 1	$ 0
200		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
201		Total Measuring and Reg. Stat. Struct.		$ 95	$ 69	$ 17	$ 2	$ 5	$ 1	$ 0
202	367	**Transmission Mains**								
203		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
204		Demand	DEM	$ 213,908	$ 156,857	$ 38,583	$ 4,018	$ 12,123	$ 1,920	$ 408

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
205		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
206		Total Transmission Mains		$ 213,908	$ 156,857	$ 38,583	$ 4,018	$ 12,123	$ 1,920	$ 408
207	368	**Compression Station Equipment**								
208		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
209		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
210		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
211		Total Compression Sta. Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
212	369	**Meas. & Reg. Station Equipment**								
213		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
214		Demand	DEM	$ 43,750	$ 32,082	$ 7,891	$ 822	$ 2,479	$ 393	$ 83
215		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
216		Total Meas. & Reg. Stat. Equipment		$ 43,750	$ 32,082	$ 7,891	$ 822	$ 2,479	$ 393	$ 83
217	371	**Other Equipment**								
218		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
219		Demand	DEM	$ 1,201	$ 881	$ 217	$ 23	$ 68	$ 11	$ 2
220		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
221		Total Other Equipment		$ 1,201	$ 881	$ 217	$ 23	$ 68	$ 11	$ 2
222	375	**Structures and Improvements**								
223		Customer	376-379CUS	$ 407	$ 386	$ 19	$ 0	$ 1	$ 0	$ 0
224		Demand	DEM	$ 296	$ 217	$ 53	$ 6	$ 17	$ 3	$ 1
225		Commodity	COM	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
226		Total Structures and Improvements		$ 703	$ 603	$ 73	$ 6	$ 18	$ 3	$ 1
227	376	**Distribution Mains**								
228		Customer	CUS	$ 4,164,994	$ 3,949,227	$ 198,413	$ 852	$ 15,025	$ 1,366	$ 110
229		Demand	DEM	$ 2,722,710	$ 1,996,534	$ 491,105	$ 51,138	$ 154,305	$ 24,440	$ 5,190
230		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
231		Total Distribution Mains		$ 6,887,704	$ 5,945,761	$ 689,518	$ 51,990	$ 169,330	$ 25,806	$ 5,300
232	378	**Meas. & Reg. Sta. Equip. - General**								
233		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
234		Demand	DEM	$ 258,168	$ 189,312	$ 46,567	$ 4,849	$ 14,631	$ 2,317	$ 492
235		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
236		Total Meas. & Reg. Sta. Eq.- General		$ 258,168	$ 189,312	$ 46,567	$ 4,849	$ 14,631	$ 2,317	$ 492
237	378	**Odorization Tank**								
238		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
239		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
240		Commodity	COM	$ 13,347	$ 7,137	$ 4,391	$ 506	$ 1,103	$ 103	$ 106
241		Total Odorization Tank		$ 13,347	$ 7,137	$ 4,391	$ 506	$ 1,103	$ 103	$ 106
242	379	**Meas.& Reg. Sta. Equip.- City Gate**								
243		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
244		Demand	DEM	$ 23,028	$ 16,886	$ 4,154	$ 433	$ 1,305	$ 207	$ 44
245		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
246		Total Meas. & Reg. Sta. Eq.- City Gate		$ 23,028	$ 16,886	$ 4,154	$ 433	$ 1,305	$ 207	$ 44
247	379	**Odorization Tank**								
248		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
249		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
250		Commodity	COM	$ 1,136	$ 608	$ 374	$ 43	$ 94	$ 9	$ 9
251		Total Odorization Tank		$ 1,136	$ 608	$ 374	$ 43	$ 94	$ 9	$ 9
252	380	**Services**								
253		Customer	SERCUS	$ 3,832,946	$ 3,613,320	$ 199,856	$ 1,100	$ 16,803	$ 1,738	$ 128
254		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
255		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
256		Total Services		$ 3,832,946	$ 3,613,320	$ 199,856	$ 1,100	$ 16,803	$ 1,738	$ 128
257	381	**Meters**								
258		Customer	METCUS	$ 2,111,908	$ 1,905,361	$ 181,912	$ 3,030	$ 18,222	$ 3,006	$ 377
259		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
260		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
261		Total Meters		$ 2,111,908	$ 1,905,361	$ 181,912	$ 3,030	$ 18,222	$ 3,006	$ 377
262	382	**Meter Installations**								
263		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
264		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
265		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
266		Total Meter Installations		$ -	$ -	$ -	$ -	$ -	$ -	$ -
267	383	**House Regulators**								
268		Customer	REGCUS	$ 182,409	$ 158,481	$ 20,985	$ 360	$ 2,150	$ 388	$ 44
269		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
270		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
271		Total House Regulators		$ 182,409	$ 158,481	$ 20,985	$ 360	$ 2,150	$ 388	$ 44
272	385	**Meas. & Reg. Sta. Eq. - Industrial**								

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
273		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
274		Demand	NRDEM	$ 243,545	$ -	$ 164,707	$ 17,151	$ 51,751	$ 8,197	$ 1,741
275		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
276		Total Meas. & Reg. Stat. Eq.- Indus.		$ 243,545	$ -	$ 164,707	$ 17,151	$ 51,751	$ 8,197	$ 1,741
277	385	**Odorization**								
278		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
279		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
280		Commodity	COM	$ 1,024	$ 547	$ 337	$ 39	$ 85	$ 8	$ 8
281		Total Odorization		$ 1,024	$ 547	$ 337	$ 39	$ 85	$ 8	$ 8
282	386	**Other Prop.- Customer Premises**								
283		Customer	CUS	$ 5,194	$ 4,925	$ 247	$ 1	$ 19	$ 2	$ 0
284		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
285		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
286		Total Other Prop. - Customer Premises		$ 5,194	$ 4,925	$ 247	$ 1	$ 19	$ 2	$ 0
287	387	**Other Equipment**								
288		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
289		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
290		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
291		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
292	389-98	**General Plant**								
293		Customer	GENPTCUS	$ 3,806,022	$ 3,588,581	$ 198,240	$ 1,256	$ 16,065	$ 1,723	$ 157
294		Demand	DISPLTDEM	$ 549,161	$ 371,614	$ 120,073	$ 12,503	$ 37,727	$ 5,975	$ 1,269
295		Commodity	COM	$ 2,813	$ 1,504	$ 925	$ 107	$ 233	$ 22	$ 22
296		Total General Plant		$ 4,357,996	$ 3,961,698	$ 319,239	$ 13,866	$ 54,024	$ 7,721	$ 1,448
297	4073	**Pension & FAS 106 Amort. Expense**								
298		Customer	CUS	$ 267,631	$ 253,766	$ 12,749	$ 55	$ 965	$ 88	$ 7
299		Demand	DEM	$ 47,914	$ 35,135	$ 8,642	$ 900	$ 2,715	$ 430	$ 91
300		Commodity	COM	$ 3,750	$ 2,005	$ 1,234	$ 142	$ 310	$ 29	$ 30
301		Total Pension & FAS 106 Amort. Exp.		$ 319,295	$ 290,906	$ 22,626	$ 1,097	$ 3,991	$ 547	$ 128
302		**Total Depreciation & Amort. Exp.**								
303		Customer		$ 14,394,809	$ 13,496,139	$ 813,533	$ 6,660	$ 69,335	$ 8,319	$ 823
304		Demand		$ 4,112,658	$ 2,806,098	$ 883,611	$ 92,008	$ 277,630	$ 43,973	$ 9,338
305		Commodity		$ 22,111	$ 11,824	$ 7,275	$ 839	$ 1,828	$ 171	$ 175
306		Total Depreciation & Amort. Expense		$ 18,529,579	$ 16,314,060	$ 1,704,419	$ 99,507	$ 348,793	$ 52,463	$ 10,336

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
307		**Taxes Other Than Income**								
308	4081	**Payroll and Other Taxes**								
309		Customer	OPEXPCUS	$ 1,829,224	$ 1,710,262	$ 107,429	$ 1,082	$ 9,128	$ 1,195	$ 128
310		Demand	OPEXPDEM	$ 327,484	$ 215,788	$ 75,539	$ 7,866	$ 23,734	$ 3,759	$ 798
311		Commodity	COM	$ 25,633	$ 13,707	$ 8,433	$ 973	$ 2,119	$ 199	$ 203
312		Total Payroll and Other Taxes		$ 2,182,341	$ 1,939,756	$ 191,401	$ 9,920	$ 34,981	$ 5,152	$ 1,130
313		**Ad Valorem Taxes**								
314		Customer	CUS	$ 2,673,825	$ 2,535,308	$ 127,376	$ 547	$ 9,646	$ 877	$ 71
315		Demand	DEM	$ 1,015,549	$ 744,691	$ 183,178	$ 19,074	$ 57,554	$ 9,116	$ 1,936
316		Commodity	COM	$ 4,760	$ 2,545	$ 1,566	$ 181	$ 393	$ 37	$ 38
317		Total Ad Valorem Taxes		$ 3,694,134	$ 3,282,544	$ 312,121	$ 19,802	$ 67,594	$ 10,030	$ 2,044
318		**Revenue Related Taxes**								
319		Customer	TOTREVCUS	$ 132,095	$ 97,607	$ 29,583	$ 1,118	$ 3,306	$ 385	$ 96
320		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
321		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
322		Total Revenue Related Taxes		$ 132,095	$ 97,607	$ 29,583	$ 1,118	$ 3,306	$ 385	$ 96
323		**Total Taxes Other Than Income**								
324		Customer		$ 4,635,144	$ 4,343,177	$ 264,389	$ 2,747	$ 22,080	$ 2,456	$ 295
325		Demand		$ 1,343,033	$ 960,479	$ 258,717	$ 26,940	$ 81,289	$ 12,875	$ 2,734
326		Commodity		$ 30,393	$ 16,252	$ 9,999	$ 1,153	$ 2,512	$ 236	$ 240
327		Total Taxes Other Than Income		$ 6,008,570	$ 5,319,908	$ 533,105	$ 30,840	$ 105,881	$ 15,567	$ 3,270
328		**Interest on Customer Deposits**								
329		Customer	DEPCUS	$ 127,096	$ 73,440	$ 52,864	$ 639	$ 138	$ 16	$ -
330		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
331		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
332		Total Interest on Cust. Deposits		$ 127,096	$ 73,440	$ 52,864	$ 639	$ 138	$ 16	$ -
333		**Required Return**								
334		Customer	CUS	$ 23,436,415	$ 22,222,296	$ 1,116,470	$ 4,797	$ 84,547	$ 7,687	$ 618
335		Demand	DEM	$ 9,122,004	$ 6,689,066	$ 1,645,367	$ 171,328	$ 516,973	$ 81,881	$ 17,387
336		Commodity	COM	$ 75,759	$ 40,510	$ 24,925	$ 2,875	$ 6,262	$ 587	$ 599
337		Total Required Return		$ 32,634,177	$ 28,951,873	$ 2,786,762	$ 179,000	$ 607,782	$ 90,155	$ 18,605
338		**Income Taxes**								
339		Customer	CUS	$ 4,904,932	$ 4,650,833	$ 233,662	$ 1,004	$ 17,694	$ 1,609	$ 129
340		Demand	DEM	$ 1,909,115	$ 1,399,933	$ 344,354	$ 35,857	$ 108,196	$ 17,137	$ 3,639

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
341		Commodity	COM	$ 15,855	$ 8,478	$ 5,216	$ 602	$ 1,311	$ 123	$ 125
342		Total Income Taxes		$ 6,829,902	$ 6,059,245	$ 583,233	$ 37,462	$ 127,201	$ 18,868	$ 3,894
343		**Total Cost of Service Before**								
344		**Revenue Credits**								
345		Customer		$ 83,349,799	$ 78,268,234	$ 4,618,306	$ 38,909	$ 375,195	$ 44,584	$ 4,571
346		Demand		$ 22,905,246	$ 15,988,700	$ 4,677,581	$ 487,065	$ 1,469,691	$ 232,779	$ 49,430
347		Commodity		$ 646,513	$ 345,709	$ 212,704	$ 24,534	$ 53,441	$ 5,010	$ 5,115
348		**Total Cost of Service Before Revenue Credits**		$ 106,901,558	$ 94,602,642	$ 9,508,590	$ 550,509	$ 1,898,327	$ 282,373	$ 59,117

ALLOCATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Customer Cost Allocation Factors**								
2									
3	Total Customers		3,185,051	3,020,051	151,730	652	11,490	1044.657895	84
4	**Total Customers Factor (CUS)**	**CUS**	**1.00000**	**0.94820**	**0.04764**	**0.00020**	**0.00361**	**0.00033**	**0.00003**
5									
6	Services Weighting			1.00000	1.10091	1.41042	1.22230	1.39076	1.27428
7	Weighted Customers		3,203,616	3,020,051	167,042	919	14,044	1,453	107
8	**Weighted Services Customer Factor (SERCUS)**	**SERCUS**	**1.00000**	**0.94270**	**0.05214**	**0.00029**	**0.00438**	**0.00045**	**0.00003**
9									
10	Meters Weighting			1.00000	1.90032	7.36773	2.51366	4.56058	7.11284
11	Weighted Customers		3,347,433	3,020,051	288,336	4,803	28,882	4,764	597
12	**Weighted Meters Customer Factor (METCUS)**	**METCUS**	**1.00000**	**0.90220**	**0.08614**	**0.00143**	**0.00863**	**0.00142**	**0.00018**
13									
14	Regulators Weighting			1.00000	2.63557	10.53428	3.56609	7.08421	9.94514
15	Weighted Customers		3,476,024	3,020,051	399,896	6,867	40,975	7,401	835
16	**Weighted Regulators Customer Factor (REGCUS)**	**REGCUS**	**1.00000**	**0.86882**	**0.11504**	**0.00198**	**0.01179**	**0.00213**	**0.00024**
17									
18	Meters and Regulators Weighting			1.00000	2.02575	7.90792	2.69319	4.99109	7.59601
19	Weighted Customers		3,369,370	3,020,051	307,367	5,155	30,945	5,214	638
20	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS)**	**MTRGCUS**	**1.00000**	**0.89632**	**0.09122**	**0.00153**	**0.00918**	**0.00155**	**0.00019**
21									
22	Non-Residential Customers		165,001	0	151,730	652	11,490	1,045	84
23	**Non-Residential Customers Factor (NRCUS)**	**NRCUS**	**1.00000**	**0.00000**	**0.91957**	**0.00395**	**0.06964**	**0.00633**	**0.00051**
24									
25	**Customer Cost Allocation Factors**								
26									
27	Distribution Plant Customer Costs		$ 400,054,007	$ 375,455,203	$ 22,293,042	$ 173,047	$ 1,889,412	$ 221,995	$ 21,308
28	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	**DISPLTCUS**	**1.00000**	**0.93851**	**0.05573**	**0.00043**	**0.00472**	**0.00055**	**0.00005**
29									
30	Account 376-379 Customer Costs		$ 183,343,142	$ 173,845,090	$ 8,734,147	$ 37,526	$ 661,408	$ 60,134	$ 4,835
31	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	**376-379CUS**	**1.00000**	**0.94820**	**0.04764**	**0.00020**	**0.00361**	**0.00033**	**0.00003**
32									
33	Total Revenue (inc. cost of gas)		$ 148,291,252	$ 109,574,681	$ 33,210,473	$ 1,254,810	$ 3,711,213	$ 431,997	$ 108,079
34	**Total Revenue (TOTREVCUS)**	**TOTREVCUS**	**1.00000**	**0.73892**	**0.22395**	**0.00846**	**0.02503**	**0.00291**	**0.00073**
35									
36	Mains - Customer Cost Factor		**0.54604**	**0.51776**	**0.02601**	**0.00011**	**0.00197**	**0.00018**	**0.00001**
37	Services - Customer Cost Factor		**0.45396**	**0.42794**	**0.02367**	**0.00013**	**0.00199**	**0.00021**	**0.00002**
38	**Mains & Svcs. Customer Factor (MSCUS)**	**MSCUS**	**1.00000**	**0.94570**	**0.04968**	**0.00024**	**0.00396**	**0.00038**	**0.00003**

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LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
39									
40	Total Plant Customer		$ 458,388,428	$ 430,767,622	$ 25,071,992	$ 184,987	$ 2,099,853	$ 241,128	$ 22,846
41	**Total Plant Factor (TPLTCUS)**	**TPLTCUS**	**1.00000**	**0.93974**	**0.05470**	**0.00040**	**0.00458**	**0.00053**	**0.00005**
42									
43	Account 871-879 Customer Costs		$ 6,480,432	$ 5,933,474	$ 486,071	$ 6,664	$ 46,309	$ 7,089	$ 824
44	**Account 871-879 Cust. Costs Factor (871-879CUS)**	**871-879CUS**	**1.00000**	**0.91560**	**0.07501**	**0.00103**	**0.00715**	**0.00109**	**0.00013**
45									
46	Account 887-893 Customer Costs		$ 1,885,132	$ 1,784,102	$ 92,575	$ 440	$ 7,264	$ 696	$ 55
47	**Account 887-893 Cust. Costs Factor (887-893CUS)**	**887-893CUS**	**1.00000**	**0.94641**	**0.04911**	**0.00023**	**0.00385**	**0.00037**	**0.00003**
48									
49	Account 903 Customer		$ 3,441,877	$ 3,317,780	$ 118,375	$ 231	$ 5,047	$ 414	$ 30
50	**Account 903 Customer Factor (903CUS)**	**903CUS**	**1.00000**	**0.96394**	**0.03439**	**0.00007**	**0.00147**	**0.00012**	**0.00001**
51									
52	**Customer Cost Allocation Factors**								
53									
54	Account 904 Customer		$ 564,333	$ 539,228	$ 23,804	$ 694	$ 694	$ (86)	$ -
55	**Account 904 Customer Factor (904CUS)**	**904CUS**	**1.00000**	**0.95551**	**0.04218**	**0.00123**	**0.00123**	**-0.00015**	**0.00000**
56									
57	Accounts 902-904 Customer		$ 5,112,811	$ 4,855,381	$ 237,498	$ 2,513	$ 15,289	$ 1,903	$ 228
58	**Accts. 902-904 Customer Factor (902-904CUS)**	**902-904CUS**	**1.00000**	**0.94965**	**0.04645**	**0.00049**	**0.00299**	**0.00037**	**0.00004**
59									
60	Operating Expense Customer		$ 30,483,967	$ 28,501,465	$ 1,790,300	$ 18,033	$ 152,120	$ 19,909	$ 2,141
61	**Operating Exp. Customer Factor (OPEXPCUS)**	**OPEXPCUS**	**1.00000**	**0.93497**	**0.05873**	**0.00059**	**0.00499**	**0.00065**	**0.00007**
62									
63	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 31,608,020	$ 29,664,484	$ 1,761,360	$ 13,672	$ 149,281	$ 17,540	$ 1,683
64	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 25,862,110	$ 24,522,330	$ 1,232,026	$ 5,293	$ 93,297	$ 8,482	$ 682
65	Total General Plant Customer Costs		$ 57,470,130	$ 54,186,813	$ 2,993,385	$ 18,966	$ 242,579	$ 26,022	$ 2,366
66	**General Plant Customer Factor (GENPTCUS)**	**GENPTCUS**	**1.00000**	**0.94287**	**0.05209**	**0.00033**	**0.00422**	**0.00045**	**0.00004**
67									
68	Customer Deposits		$ (6,619,573)	$ (3,824,975)	$ (2,753,338)	$ (33,266)	$ (7,173)	$ (822)	$ -
69	**Customer Deposits Factor (DEPCUS)**	**DEPCUS**	**1.00000**	**0.57783**	**0.41594**	**0.00503**	**0.00108**	**0.00012**	**0.00000**
70									
71	**Demand Cost Allocation Factors**								
72									
73	System Demand								
74	**System Demand Factor (DEM)**	**DEM**	**1.00000**	**0.73329**	**0.18037**	**0.01878**	**0.05667**	**0.00898**	**0.00191**
75									
76	Non-Residential Demand								
77	**Non-Residential Demand Factor (NRDEM)**	**NRDEM**	**1.00000**	**0.00000**	**0.67629**	**0.07042**	**0.21249**	**0.03366**	**0.00715**
78									
79	Distribution Plant Demand		$ 147,374,612	$ 99,727,439	$ 32,223,235	$ 3,355,328	$ 10,124,509	$ 1,603,584	$ 340,517
80	**Distribution Plant Demand Factor (DISPLTDEM)**	**DISPLTDEM**	**1.00000**	**0.67669**	**0.21865**	**0.02277**	**0.06870**	**0.01088**	**0.00231**
81									
82	**Demand Cost Allocation Factors**								
83									
84	Total Plant Demand		$ 174,101,199	$ 119,325,755	$ 37,044,002	$ 3,857,303	$ 11,639,189	$ 1,843,489	$ 391,460

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LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
85	**Total Plant Demand Factor (TPLTDEM)**	**TPLTDEM**	**1.00000**	**0.68538**	**0.21277**	**0.02216**	**0.06685**	**0.01059**	**0.00225**
86									
87	Operating Expense Demand		$ 8,002,918	$ 5,273,337	$ 1,845,984	$ 192,218	$ 580,006	$ 91,865	$ 19,507
88	**Operating Expense Demand Factor (OPEXPDEM)**	**OPEXPDEM**	**1.00000**	**0.65893**	**0.23066**	**0.02402**	**0.07247**	**0.01148**	**0.00244**
89									
90	Acct. 887-893 Demand		$ 1,570,517	$ 834,115	$ 498,020	$ 51,858	$ 156,477	$ 24,784	$ 5,263
91	**Acct. 887-893 Demand Factor (887-893DEM)**	**887-893DEM**	**1.00000**	**0.53111**	**0.31711**	**0.03302**	**0.09963**	**0.01578**	**0.00335**
92									
93	Rate Base Demand		$ 115,081,609	$ 78,408,926	$ 24,801,313	$ 2,582,501	$ 7,792,548	$ 1,234,233	$ 262,087
94	**Rate Base Demand Factor (RBDEM)**	**RBDEM**	**1.00000**	**0.68133**	**0.21551**	**0.02244**	**0.06771**	**0.01072**	**0.00228**
95									
96	**Commodity Cost Allocation Factors**								
97									
98	Annual Distribution Volumes (Ccf)		170,966,399	91,420,587	56,248,281	6,487,919	14,132,147	1,324,758	1,352,707
99	**Distribution Commodity Factor (COM)**	**COM**	**1.00000**	**0.53473**	**0.32900**	**0.03795**	**0.08266**	**0.00775**	**0.00791**

CLASS REVENUE ALLOCATION

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS REVENUE ALLOCATION

LINE	DESCRIPTION (a)	TOTAL (b)	RESIDENTIAL (c)	COMMERCIAL (d)	INDUSTRIAL (e)	PUBLIC AUTHORITY (f)	COMPRESSED NAT. GAS (g)
1	Current Revenue-to-Cost Ratio (1)	0.8518	0.7554	1.6517	1.7516	1.2940	1.8399
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
5	Rate Design Revenue Increase	$ 15,842,399	$ 23,143,400	$ (6,196,467)	$ (413,740)	$ (641,142)	$ (49,652)
6	% Increase - Non-Gas Revenue (2)	17.40%	32.39%	-39.46%	-42.91%	-22.72%	-45.65%
7	% Increase - Total Revenue (3)	10.41%	20.44%	-18.53%	-32.73%	-15.34%	-45.53%
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)						
9	Revenue-to-Cost Ratio	1.0000	0.9383	1.5213	1.6012	1.2352	1.6719
10	Rate Design Revenue Increase	$ 15,842,399	$ 17,302,600	$ (1,239,293)	$ (82,748)	$ (128,228)	$ (9,930)
11	% Increase - Non-Gas Revenue (2)	17.40%	24.21%	-7.89%	-8.58%	-4.54%	-9.13%
12	% Increase - Total Revenue (3)	10.41%	15.28%	-3.71%	-6.55%	-3.07%	-9.11%
13	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)						
14	Revenue-to-Cost Ratio	1.0000	0.9228	1.6517	1.7516	1.2940	1.8399
15	Rate Design Revenue Increase	$ 15,842,399	$ 15,842,399	$ -	$ -	$ -	$ -
16	% Increase - Non-Gas Revenue (2)	17.40%	22.17%	0.00%	0.00%	0.00%	0.00%
17	% Increase - Total Revenue (3)	10.41%	14.00%	0.00%	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.

STUDY SUMMARY

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

CLASS COST OF SERVICE STUDY SUMMARY

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)
1	Customer Costs	$ 15,714,320	$ 14,854,285	$ 737,535	$ 85,306	$ 37,194
2	Demand Costs	$ 3,303,972	$ 2,297,508	$ 653,160	$ 257,735	$ 95,569
3	Commodity Costs	$ 118,736	$ 67,578	$ 40,448	$ 7,436	$ 3,274
4	Cost of Service Before Revenue Credits	$ 19,137,027	$ 17,219,371	$ 1,431,143	$ 350,477	$ 136,037
5	Revenues Credited to Cost of Service (1)	$ 1,412,574	$ 1,288,728	$ 94,719	$ 20,802	$ 8,325
6	Total Cost of Service	$ 17,724,453	$ 15,930,643	$ 1,336,424	$ 329,674	$ 127,712
7	Revenue at Current Rates	$ 16,532,474	$ 12,780,232	$ 2,927,782	$ 269,721	$ 554,740
8	Revenue Deficiency	$ 1,191,979	$ 3,150,411	$ (1,591,358)	$ 59,954	$ (427,028)
9	Revenue-to-Cost Ratios:					
10	Current Revenue	0.9377	0.8170	2.1119	0.8289	4.1391
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge, special contract, 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	$ 276,705
Special Contract	$ 1,133,214
Unmetered Service	$ 2,655
	$ 1,412,574

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STUDY SUMMARY FOR REV. ALLOC.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

CLASS COST OF SERVICE STUDY SUMMARY FOR REVENUE ALLOCATION

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)
1	Customer Costs	$ 15,714,320	$ 14,854,285	$ 737,535	$ 85,306	$ 37,194
2	Demand Costs	$ 3,303,972	$ 2,297,508	$ 653,160	$ 257,735	$ 95,569
3	Commodity Costs	$ 118,736	$ 67,578	$ 40,448	$ 7,436	$ 3,274
4	Cost of Service Before Revenue Credits	$ 19,137,027	$ 17,219,371	$ 1,431,143	$ 350,477	$ 136,037
5	Revenues Credited to Cost of Service	$ 1,412,574	$ 1,288,728	$ 94,719	$ 20,802	$ 8,325
6	Total Cost of Service	$ 26,044,857	$ 15,930,643	$ 1,336,424	$ 329,674	$ 127,712
7	Revenue at Current Rates	$ 16,532,474	$ 12,780,232	$ 2,927,782	$ 269,721	$ 554,740
8	Revenue Deficiency	$ 1,191,979	$ 3,150,411	$ (1,591,358)	$ 59,954	$ (427,028)
9	Revenue-to-Cost Ratios					
10	Current Revenue	0.9377	0.8170	2.1119	0.8289	4.1391
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000
	Customer and Demand Costs Per Bill		$ 33.77	$ 62.94	$ 7,146.67	$ 41.83
	Commodity Cost Per Cff	$ 0.0048				

CLASSIFIED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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	$ 6,556	$ 5,291	$ 1,245	$ 20
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 4,313	$ 3,481	$ 819	$ 13
4		Total Intangible Plant		$ 10,869	$ 8,772	$ 2,064	$ 33
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	$ 28,374	$ 17,785	$ 10,434	$ 156
17	375	Structures and Improvements	DIS376-379	$ 30,457	$ 19,090	$ 11,200	$ 167
18	376	Distribution Mains	MAINS	$ 37,395,634	$ 25,151,865	$ 12,243,769	$ -
19	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
20	378	Meas. & Reg. Sta. Equip.- General	DEM	$ 1,532,619	$ -	$ 1,532,619	$ -
21	378	Odorization Tank	COM	$ 57,523	$ -	$ -	$ 57,523
22	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 979,424	$ -	$ 979,424	$ -
23	379	Odorization Tank	COM	$ 219,992	$ -	$ -	$ 219,992
24	380	Services	CUS	$ 33,201,388	$ 33,201,388	$ -	$ -
25	381	Meters	CUS	$ 12,059,717	$ 12,059,717	$ -	$ -
26	382	Meter Installations	CUS	$ 4,223	$ 4,223	$ -	$ -
27	383	House Regulators	CUS	$ 1,780,463	$ 1,780,463	$ -	$ -

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
28	385	Meas. & Reg. Sta. Equipment - Industrial	DEM	$ 3,163,852	$ -	$ 3,163,852	$ -
29	386	Other Property - Customer Premises	CUS	$ 71,409	$ 71,409	$ -	$ -
30	387	Other Equipment		$ -	$ -	$ -	$ -
31		Total Distribution Plant		$ 90,525,075	$ 72,305,940	$ 17,941,297	$ 277,837
32							
33		General Plant					
34	389	Land & Land Rights	GENPLT	$ 77,650	$ 69,168	$ 8,353	$ 129
35	390	Structures & Improvements	GENPLT	$ 3,078,155	$ 2,519,691	$ 549,948	$ 8,516
36	391	Office Furniture and Equipment	GENPLT	$ 4,250,865	$ 4,192,388	$ 57,586	$ 892
37	392	Transportation Equipment	GENPLT	$ 2,008,880	$ 1,604,571	$ 398,143	$ 6,166
38	393	Stores Equipment	GENPLT	$ 3,423	$ 2,734	$ 678	$ 11
39	394	Tools, Shop & Garage	GENPLT	$ 1,121,178	$ 895,801	$ 221,940	$ 3,437
40	394	Odorization Tank	COM	$ 14,329	$ -	$ -	$ 14,329
41	395	CNG Equipment	GENPLT	$ -	$ -	$ -	$ -
42	396	Major Work Equipment	GENPLT	$ 454,183	$ 362,774	$ 90,015	$ 1,394
43	397	Communication Equipment	GENPLT	$ 2,936,612	$ 2,345,587	$ 582,011	$ 9,013
44	398	Miscellaneous General Plant	GENPLT	$ 74,456	$ 74,456	$ 0	$ 0
45		Total General Plant		$ 14,019,732	$ 12,067,170	$ 1,908,675	$ 43,887
46							
47		Total Plant in Service		$ 104,555,676	$ 84,381,882	$ 19,852,036	$ 321,758
48							
49		Depreciation & Amortization Reserve					
50		Intangible Plant	NONINTPLT	$ (12,858)	$ (10,377)	$ (2,441)	$ (40)
51		Transmission Plant	DEM	$ -	$ -	$ -	$ -
52		Distribution Plant	DISPLTRES	$ (21,312,284)	$ (16,817,051)	$ (4,529,610)	$ 34,376
53		General Plant	GENPLTRES	$ (5,137,687)	$ (4,377,346)	$ (753,877)	$ (6,465)
54		Total Depreciation & Amortization Reserve		$ (26,462,830)	$ (21,204,774)	$ (5,285,928)	$ 27,872
55							
56		Net Plant in Service		$ 78,092,846	$ 63,177,108	$ 14,566,108	$ 349,630
57							
58		Customer Deposits	CUS	$ (1,234,179)	$ (1,234,179)	$ -	$ -
59							
60		Customer Advances	MAINS/SVCS	$ (517,538)	$ (427,780)	$ (89,758)	$ -
61							
62		Accumulated Deferred Income Taxes	TOTPLT	$ (18,396,483)	$ (14,846,921)	$ (3,492,949)	$ (56,613)

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LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
63							
64		Materials and Supplies	TOTPLT	$ 609,661	$ 492,029	$ 115,757	$ 1,876
65							
66		Prepayments	OPEXP	$ 373,558	$ 306,328	$ 64,089	$ 3,141
67							
68		Pension & FAS 106 Regulatory Asset	OPEXP	$ 3,446,436	$ 2,826,175	$ 591,286	$ 28,975
69							
70		DIMP Deferrals	OPEXP	$ 60,595	$ 49,690	$ 10,396	$ 509
71							
72		Cash Working Capital	OPEXP	$ (705,220)	$ (578,300)	$ (120,991)	$ (5,929)
73							
74		Total Rate Base		$ 61,729,677	$ 49,764,149	$ 11,643,939	$ 321,589

CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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	850-66	Transmission Expenses	DEM	$ 98,226	$ -	$ 98,226	$ -
3	870	Operation Supervision & Engineering	DIS871-879	$ 199,066	165,872	28,550	$ 4,643
4	870	Odorization	COM	$ 814	$ -	$ -	$ 814
5	871	Distribution Load Dispatch	COM	$ 37,648	-	-	$ 37,648
6	874	Mains and Services Expenses	MAINS/SVCS	$ 826,074	$ 682,807	$ 143,268	$ -
7	874	Odorization	COM	$ 657	$ -	$ -	$ 657
8	875	Measuring & Reg. Station Expense - General	DEM	$ 81,596	$ -	$ 81,596	$ -
9	875	Odorization	COM	$ 7,895	$ -	$ -	$ 7,895
10	876	Meas. & Reg. Station Expense.- Industrial	DEM	$ 6,091	$ -	$ 6,091	$ -
11	877	Meas. & Regulating Station Exp.- City Gate	DEM	$ 536	$ -	$ 536	$ -
12	878	Meter and House Regulator Expenses	CUS	$ 683,077	$ 683,077	$ -	$ -
13	879	Customer Installation Expenses	CUS	$ (20,955)	$ (20,955)	$ -	$ -
14	880	Other Expenses	CUS	$ 219,569	$ 219,569	$ -	$ -
15	880	Odorization	COM	$ -	$ -	$ -	$ -
16	881	Rents	DIS871-879	$ 4,055	$ 3,379	$ 582	$ 95
17		Total Transmission & Distribution Oper. Exp.		$ 2,144,348	$ 1,733,749	$ 358,849	$ 51,751
18							
19		Distribution Maintenance Expenses					
20	885	Maintenance Supervision and Engineering	DIS887-893	$ 72	$ 42	$ 30	$ -
21	886	Structures and Improvements	DIS887-893	$ 120,734	$ 71,104	$ 49,630	$ -
22	887	Maintenance of Mains	MAINS	$ 1,083,472	$ 728,730	$ 354,741	$ -
23	889	Maint. of Meas. & Reg. Sta. Equip.- General	DEM	$ 142,764	$ -	$ 142,764	$ -
24	890	Maint. of Meas. & Reg. Sta. Equip. - Industrial	DEM	$ 150,045	$ -	$ 150,045	$ -
25	891	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 11	$ -	$ 11	$ -
26	892	Maintenance of Services	CUS	$ 199,027	$ 199,027	$ -	$ -
27	893	Main. of Meters & House Regulators	CUS	$ -	$ -	$ -	$ -
28	894	Maintenance of Other Equipment	DIS887-893	$ -	$ -	$ -	$ -

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LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
29		Total Distribution Maintenance Expenses		$ 1,696,125	$ 998,904	$ 697,221	$ -
30							
31		Total Operations & Maintenance Expenses		$ 3,840,473	$ 2,732,653	$ 1,056,070	$ 51,751
32							
33		Customer Accounts Expenses					
34	901	Supervision	CUS	$ 22,354	$ 22,354	$ -	$ -
35	902	Meter Reading Expense	CUS	$ 231,223	$ 231,223	$ -	$ -
36	903	Customer Accounting	CUS	$ 667,360	$ 667,360	$ -	$ -
37	904	Bad Debts (includes gross up)	CUS	$ 111,129	$ 111,129	$ -	$ -
38	905	Miscellaneous Customer Accounts Expenses	CUS	$ 61,644	$ 61,644	$ -	$ -
39		Total Customer Accounts Expenses		$ 1,093,709	$ 1,093,709	$ -	$ -
40							
41		Customer Service Expenses					
42	907	Supervision	CUS	$ -	$ -	$ -	$ -
43	908	Customer Assistance	CUS	$ 115,659	$ 115,659	$ -	$ -
44	909	Informational and Instructional Advertising	CUS	$ 13,499	$ 13,499	$ -	$ -
45		Total Customer Service Expenses		$ 129,158	$ 129,158	$ -	$ -
46							
47		Sales and Advertising Expenses					
48	912	Demonstrating and Selling	CUS	$ -	$ -	$ -	$ -
49	913	Advertising	CUS	$ 305	$ 305	$ -	$ -
50		Total Sales and Advertising Expenses		$ 305	$ 305	$ -	$ -
51							
52		Administrative & General Expenses					
53	921-32	Administrative & General Expenses	ADMINGEN	$ 3,811,562	$ 3,322,095	$ 466,602	$ 22,865
54		Total Administrative & General Expenses		$ 3,811,562	$ 3,322,095	$ 466,602	$ 22,865
55							
56		Depreciation and Amortization Expense					
57	301-303	Intangible Plant	PLT301-03	$ -	$ -	$ -	$ -
58	365	Land and Land Rights	DEM	$ -	$ -	$ -	$ -
59	366	Meas. and Reg. Station Structures	PLT366	$ -	$ -	$ -	$ -
60	367	Transmission Mains	PLT367	$ -	$ -	$ -	$ -
61	368	Compression Station Equipment	PLT368	$ -	$ -	$ -	$ -
62	369	Measuring and Reg. Station Equipment	PLT369	$ -	$ -	$ -	$ -
63	371	Other Equipment	PLT371	$ -	$ -	$ -	$ -

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LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
64	375	Structures and Improvements	PLT375	$ 540	$ 339	$ 199	$ 3
65	376	Mains	PLT376	$ 798,999	$ 537,397	$ 261,602	$ -
66	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
67	378	Meas. & Reg. Sta. Equipment - General	PLT378	$ 34,024	$ -	$ 34,024	$ -
68	378	Odorization Tank	COM	$ 1,277	$ -	$ -	$ 1,277
69	379	Meas. & Reg. Sta. Equipment - City Gate	PLT379	$ 17,728	$ -	$ 17,728	$ -
70	379	Odorization Tank	COM	$ 3,982	$ -	$ -	$ 3,982
71	380	Services	PLT380	$ 900,559	$ 900,559	$ -	$ -
72	381	Meters	PLT381	$ 541,481	$ 541,481	$ -	$ -
73	382	Meter Installations	PLT382	$ 60	$ 60	$ -	$ -
74	383	House Regulators	PLT383	$ 51,277	$ 51,277	$ -	$ -
75	385	Meas. & Reg. Sta. Equip. - Industrial	PLT385	$ 68,656	$ -	$ 68,656	$ -
76	386	Other Property - Customer Premises	PLT386	$ 5,220	$ 5,220	$ -	$ -
77	387	Other Equipment		$ -	$ -	$ -	$ -
78	389-98	General Plant	GENDEP	$ 751,708	$ 674,148	$ 75,437	$ 2,123
79	4073	Pension & FAS 106 Amortization Expense	OPEXP	$ 11,551	$ 9,472	$ 1,982	$ 97
80		Total Depreciation and Amortization Expense		$ 3,187,063	$ 2,719,955	$ 459,626	$ 7,482
81							
82		Taxes Other Than Income					
83	408	Payroll and Other	OPEXP	$ 440,450	$ 361,181	$ 75,566	$ 3,703
84	408	Ad Valorem	TOTPLT	$ 683,528	$ 551,643	$ 129,782	$ 2,103
85	408	Revenue Related (includes gross up)	CUS	$ 8,940	$ 8,940	$ -	$ -
86		Total Taxes Other Than Income		$ 1,132,918	$ 921,763.87	$ 205,347.40	$ 5,806.43
87							
88	431	Interest on Customer Deposits	CUS	$ 23,696	$ 23,696	$ -	$ -
89							
90		Required Return	RB	$ 4,893,035	$ 3,944,581	$ 922,963	$ 25,491
91		Income Taxes	RB	$ 1,025,107	$ 826,403	$ 193,364	$ 5,340
92		Total Cost of Service Before Revenue Credits		$ 19,137,027	$ 15,714,320	$ 3,303,972	$ 118,736

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CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**CUS**	**Customer Factor**		**1.00000**	**0.00000**	**0.00000**
2							
3		**DEM**	**Demand Factor**		**0.00000**	**1.00000**	**0.00000**
4							
5		**COM**	**Commodity Factor**		**0.00000**	**0.00000**	**1.00000**
6							
7		**DEM-COM**	**Demand and Commodity Factor**		**0.00000**	**0.50000**	**0.50000**
8							
9			Total Transmission Plant	$ -	$ -	$ -	$ -
10			Total Distribution Plant	$ 90,525,075	$ 72,305,940	$ 17,941,297	$ 277,837
11			Total General Plant	$ 14,019,732	$ 12,067,170	$ 1,908,675	$ 43,887
12			Total Non-Intangible Plant	$ 104,544,807	$ 84,373,110	$ 19,849,972	$ 321,724
13		**NONINTPLT**	**Non-Intangible Plant Factor**	**1.00000**	**0.80705**	**0.18987**	**0.00308**
14							
15	376		Distribution Mains	$ 37,395,634	$ 25,151,865	$ 12,243,769	$ -
16	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
17	378		Meas. & Reg. Sta. Equip.- General	$ 1,532,619	$ -	$ 1,532,619	$ -
18	379		Meas. & Reg. Sta. Equip.- City Gate	$ 1,199,416	$ -	$ 979,424	$ 219,992
19			Total Accounts 376-379	$ 40,127,669	$ 25,151,865	$ 14,755,812	219,992
20		**DIS376-379**	**Accounts 376-379 Factor**	**1.00000**	**0.62680**	**0.36772**	**0.00548**
21							
22	376		Mains	$ 37,395,634	$ 25,151,865	$ 12,243,769	$ -
23		**MAINS**	**Distribution Mains Factor**	**1.00000**	**0.67259**	**0.32741**	**0.00000**
24							
25	376/380		Mains and Services	$ 70,597,021	$ 58,353,252	$ 12,243,769	$ -
26		**MAINS/SVCS**	**Mains and Services Factor**	**1.00000**	**0.82657**	**0.17343**	**0.00000**
27							
28	374-87		Total Distribution Plant	$ 90,525,075	$ 72,305,940	$ 17,941,297	$ 277,837

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LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
29		**DISPLT**	**Distribution Plant Factor**	**1.00000**	**0.79874**	**0.19819**	**0.00307**
30							
31			General Plant Reserve	$ (5,137,687)	$ (4,377,346)	$ (753,877)	$ (6,465)
32		**GENPLTRES**	**General Plant Reserve Factor**	**1.00000**	**0.85201**	**0.14673**	**0.00126**
33							
34			Total Plant	$ 104,555,676	$ 84,381,882	$ 19,852,036	$ 321,758
35		**TOTPLT**	**Total Plant Factor**	**1.00000**	**0.80705**	**0.18987**	**0.00308**
36							
37	374		Land & Land Rights	$ (2,285)	$ (1,432)	$ (840)	$ (13)
38	375		Structures and Improvements	$ 25,060	$ 15,708	$ 9,215	$ 137
39	376		Distribution Mains	$ (8,353,228)	$ (5,618,283)	$ (2,734,945)	$ -
40	378		Meas. & Reg. Station Equip.- General	$ (389,978)	$ -	$ (389,978)	$ -
41	379		Meas. & Reg. Station Equip.- City Gate	$ (345,996)	$ -	$ (345,996)	$ -
42	379		Odorization Tank	$ 34,612	$ -	$ -	$ 34,612
43	380		Services	$ (6,973,822)	$ (6,973,822)	$ -	$ -
44	381		Meters	$ (3,662,682)	$ (3,662,682)	$ -	$ -
45	382		Meter Installations	$ (4,427)	$ (4,427)	$ -	$ -
46	383		House Regulators	$ (542,670)	$ (542,670)	$ -	$ -
47	385		Meas. & Reg. Sta. Equipment - Industrial	$ (1,046,765)	$ -	$ (1,046,765)	$ -
48	386		Other Property - Customer Premises	$ (62,197)	$ (38,985)	$ (22,871)	$ (341)
49	378		Other Equipment	$ -			
50			Total Distribution Plant Reserve	$ (21,324,377)	$ (16,826,593)	$ (4,532,180)	$ 34,396
51		**DISPLTRES**	**Distribution Plant Reserve**	**1.00000**	**0.78908**	**0.21254**	**(0.00161)**
52							
53			Total Operations and Maintenance Expenses	$ 3,840,473	$ 2,732,653	$ 1,056,070	$ 51,751
54			Total Customer Accounts Expenses	$ 1,093,709	$ 1,093,709	$ -	$ -
55			Total Customer Service Expenses	$ 129,158	$ 129,158	$ -	$ -
56			Total Sales and Advertising Expenses	$ 305	$ 305	$ -	$ -
57			Administrative and General Expenses	$ 3,811,562	$ 3,322,095	$ 466,602	$ 22,865
58			Total Operating Expenses	$ 8,875,208	$ 7,277,921	$ 1,522,672	$ 74,616
59		**OPEXP**	**Operating Expense Factor**	**1.00000**	**0.82003**	**0.17156**	**0.00841**
60							
61	871		Distribution Load Dispatch	$ 37,648	$ -	$ -	$ 37,648
62	874		Mains and Services Expenses	$ 826,074	$ 682,807	$ 143,268	$ -
63	875		Measuring & Reg. Station Expense - General	$ 81,596	$ -	$ 81,596	$ -

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LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
64	876		Meas. & Reg. Station Expense.- Industrial	$ 6,091	$ -	$ 6,091	$ -
65	877		Meas. & Regulating Station Exp.- City Gate	$ 536	$ -	$ 536	$ -
66	878		Meter and House Regulator Expenses	$ 683,077	$ 683,077	$ -	$ -
67	879		Customer Installation Expenses	$ (20,955)	$ (20,955)	$ -	$ -
68			Total Accounts 871-879	$ 1,614,068	$ 1,344,929	$ 231,491	$ 37,648
69		**DIS871-879**	**Accounts 871-879 Factor**	**1.00000**	**0.83325**	**0.14342**	**0.02332**
70							
71	887		Maintenance of Mains	$ 1,083,472	$ 728,730	$ 354,741	$ -
72	889		Maint. of Meas. & Reg. Sta. Equip.- General	$ 142,764	$ -	$ 142,764	$ -
73	890		Maint. of Meas. & Reg. Sta. Equip. - Industrial	$ 150,045	$ -	$ 150,045	$ -
74	891		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 11	$ -	$ 11	$ -
75	892		Maintenance of Services	$ 199,027	$ 199,027	$ -	$ -
76	893		Main. of Meters & House Regulators	$ -	$ -	$ -	$ -
77			Total Accounts 887-893	$ 1,575,320	$ 927,758	$ 647,562	$ -
78		**DIS887-893**	**Accounts 887-893 Factor**	**1.00000**	**0.58893**	**0.41107**	**0.00000**
79							
80			Total Operations and Maintenance Expenses	$ 3,840,473	$ 2,732,653	$ 1,056,070	$ 51,751
81			Total Customer Accounts Expenses	$ 1,093,709	$ 1,093,709	$ -	-
82			Total Customer Service Expenses	$ 129,158	$ 129,158	$ -	-
83			Total Sales and Advertising Expenses	$ 305	$ 305	$ -	$ -
84			Total Operating Exp. Without A&G Expenses	$ 5,063,645	$ 3,955,825	$ 1,056,070	$ 51,751
85		**NONAGOPEXP**	**Non-A&G Operating Expenses Factor**	**1.00000**	**0.78122**	**0.20856**	**0.01022**
86							
87	920-932		Administrative and General Expenses	$ 3,811,562	$ 3,322,095	$ 466,602	$ 22,865
88		**ADMINGEN**	**Administrative and General Expenses Factor**	**1.00000**	**0.87158**	**0.12242**	**0.00600**
89							
90	366		Meas. and Reg. Station Structures	$ -	$ -	$ -	$ -
91		**PLT366**	**Measuring and Reg. Station Structures Factor**	**0.00000**	**0.00000**	**0.00000**	**0.00000**
92							
93	367		Transmission Mains	$ -	$ -	$ -	$ -
94		**PLT367**	**Transmission Mains**	**0.00000**	**0.00000**	**0.00000**	**0.00000**
95							
96	368		Compression Station Equipment	$ -	$ -	$ -	$ -
97		**PLT368**	**Compression Station Equipment Factor**	**0.00000**	**0.00000**	**0.00000**	**0.00000**
98							

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LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
99	369		Measuring and Reg. Station Equipment	$ -	$ -	$ -	$ -
100		**PLT369**	**Measuring & Reg, Station Equipment Factor**	**0.00000**	**0.00000**	**0.00000**	**0.00000**
101							
102	371		Other Equipment	$ -	$ -	$ -	$ -
103		**PLT371**	**Other Equipment Factor**	**0.00000**	**0.00000**	**0.00000**	**0.00000**
104							
105	375		Structures and Improvements	$ 30,457	$ 19,090	$ 11,200	$ 167
106		**PLT375**	**Structures and Improvements Factor**	**1.00000**	**0.62680**	**0.36772**	**0.00548**
107							
108	376		Distribution Mains	$ 37,395,634	$ 25,151,865	$ 12,243,769	$ -
109		**PLT376**	**Distribution Mains Factor**	**1.00000**	**0.67259**	**0.32741**	**0.00000**
110							
111	378		Meas. & Reg. Sta. Equip.- General	$ 1,532,619	$ -	$ 1,532,619	$ -
112		**PLT378**	**Meas. & Reg. Station Equip. - General Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
113							
114	379		Meas. & Reg. Sta. Equip.- City Gate	$ 979,424	$ -	$ 979,424	$ -
115		**PLT379**	**Meas. & Reg. Station Equip. - City Gate Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
116							
117	380		Services	$ 33,201,388	$ 33,201,388	$ -	$ -
118		**PLT380**	**Services Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
119							
120	381		Meters	$ 12,059,717	$ 12,059,717	$ -	$ -
121		**PLT381**	**Meters Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
122							
123	382		Meter Installations	$ 4,223	$ 4,223	$ -	$ -
124		**PLT382**	**Meter Installations Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
125							
126	383		House Regulators	$ 1,780,463	$ 1,780,463	$ -	$ -
127		**PLT383**	**House Regulators Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
128							
129	385		Meas. & Reg. Sta. Equipment - Industrial	$ 3,163,852	$ -	$ 3,163,852	$ -
130		**PLT385**	**Meas. & Reg. Sta. Equip.-Industrial Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
131							
132	386		Other Property - Customer Premises	$ 71,409	$ 71,409	$ -	$ -
133		**PLT386**	**Other Property-Customer Premises Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
134							
135	301-03		Intangible Plant	$ 10,869	$ 8,772	$ 2,064	$ 33
136		**PLT301-03**	**Intangible Plant**	**1.00000**	**0.80705**	**0.18987**	**0.00308**
137							
138	389-98		General Plant Depreciation Expense	$ 751,708	$ 674,148	$ 75,437	$ 2,123
139		**GENDEP**	**General Plant Depreciation Expense Factor**	**1.00000**	**0.89682**	**0.10035**	**0.00282**
140							
141			Rate Base	$ 61,729,677	$ 49,764,149	$ 11,643,939	$ 321,589
142		**RB**	**Rate Base Factor**	**1.00000**	**0.80616**	**0.18863**	**0.00521**

ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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	CUS	$ 8,772	$ 8,356	$ 363	$ 52	$ 1
3		Demand	DEM	$ 2,064	$ 1,599	$ 302	$ 148	$ 15
4		Commodity	COM	$ 33	$ 19	$ 11	$ 2	$ 1
		Total Intangible Plant		$ 10,869	$ 9,974	$ 676	$ 203	$ 16
5	365-371	**Transmission Plant**						
6		Customer	CUS	$ -	$ -	$ -	$ -	$ -
7		Demand	DEM	$ -	$ -	$ -	$ -	$ -
8		Commodity	COM	$ -	$ -	$ -	$ -	$ -
9		Total Transmission Plant		$ -	$ -	$ -	$ -	$ -
10		**Distribution Plant**						
11	374	**Land & Land Rights**						
12		Customer	CUS	$ 17,785	$ 16,940	$ 737	$ 106	$ 2
13		Demand	DEM	$ 10,434	$ 8,085	$ 1,525	$ 751	$ 74
14		Commodity	COM	$ 156	$ 89	$ 53	$ 10	$ 4
15		Total Land & Land Rights		$ 28,374	$ 25,114	$ 2,314	$ 866	$ 80
16	375	**Structures and Improvements**						
17		Customer	CUS	$ 19,090	$ 18,184	$ 791	$ 114	$ 2
18		Demand	DEM	$ 11,200	$ 8,678	$ 1,636	$ 806	$ 79
19		Commodity	COM	$ 167	$ 95	$ 57	$ 10	$ 5
20		Total Structures and Improvements		$ 30,457	$ 26,957	$ 2,484	$ 930	$ 86
21	376	**Distribution Mains**						
22		Customer	CUS	$ 25,151,865	$ 23,957,717	$ 1,042,176	$ 149,707	$ 2,264
23		Demand	DEM	$ 12,243,769	$ 9,487,124	$ 1,788,967	$ 880,783	$ 86,895
24		Commodity	COM	$ -	$ -	$ -	$ -	$ -
25		Total Distribution Mains		$ 37,395,634	$ 33,444,842	$ 2,831,143	$ 1,030,490	$ 89,159
26	377	**Compressor Station Equipment**						
27		Customer	CUS	$ -	$ -	$ -	$ -	$ -

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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
28		Demand	DEM	$ -	$ -	$ -	$ -	$ -
29		Commodity	COM	$ -	$ -	$ -	$ -	$ -
30		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -
31	378	**Meas. & Reg. Sta. Equip. - General**						
32		Customer	CUS	$ -	$ -	$ -	$ -	$ -
33		Demand	DEM	$ 1,532,619	$ 1,187,555	$ 223,935	$ 110,252	$ 10,877
34		Commodity	COM	$ -	$ -	$ -	$ -	$ -
35		Total Meas. & Reg. Sta. Equip.- Gen.		$ 1,532,619	$ 1,187,555	$ 223,935	$ 110,252	$ 10,877
36	378	**Odorization Tank**						
37		Customer	CUS	$ -	$ -	$ -	$ -	$ -
38		Demand	DEM	$ -	$ -	$ -	$ -	$ -
39		Commodity	COM	$ 57,523	$ 32,739	$ 19,595	$ 3,603	$ 1,586
40		Total Odorization Tank		$ 57,523	$ 32,739	$ 19,595	$ 3,603	$ 1,586
41	379	**Meas. & Reg. Station - City Gate**						
42		Customer	CUS	$ -	$ -	$ -	$ -	$ -
43		Demand	DEM	$ 979,424	$ 758,910	$ 143,106	$ 70,457	$ 6,951
44		Commodity	COM	$ -	$ -	$ -	$ -	$ -
45		Total Meas. & Reg. Equip.-City Gate		$ 979,424	$ 758,910	$ 143,106	$ 70,457	$ 6,951
46	379	**Odorization Tank**						
47		Customer	CUS	$ -	$ -	$ -	$ -	$ -
48		Demand	DEM	$ -	$ -	$ -	$ -	$ -
49		Commodity	COM	$ 219,992	$ 125,208	$ 74,942	$ 13,778	$ 6,065
50		Total Odorization Tank		$ 219,992	$ 125,208	$ 74,942	$ 13,778	$ 6,065
51	380	**Services**						
52		Customer	SERCUS	$ 33,201,388	$ 31,395,586	$ 1,576,114	$ 224,538	$ 5,150
53		Demand	DEM	$ -	$ -	$ -	$ -	$ -
54		Commodity	COM	$ -	$ -	$ -	$ -	$ -
55		Total Services		$ 33,201,388	$ 31,395,586	$ 1,576,114	$ 224,538	$ 5,150
56	381	**Meters**						
57		Customer	METCUS	$ 12,059,717	$ 11,053,302	$ 814,007	$ 183,382	$ 9,026
58		Demand	DEM	$ -	$ -	$ -	$ -	$ -
59		Commodity	COM	$ -	$ -	$ -	$ -	$ -
60		Total Meters		$ 12,059,717	$ 11,053,302	$ 814,007	$ 183,382	$ 9,026
61	382	**Meter Installations**						
62		Customer	METCUS	$ 4,223	$ 3,871	$ 285	$ 64	$ 3

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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
63		Demand	DEM	$ -	$ -	$ -	$ -	$ -
64		Commodity	COM	$ -	$ -	$ -	$ -	$ -
65		Total Meter Installations		$ 4,223	$ 3,871	$ 285	$ 64	$ 3
66	383	**House Regulators**						
67		Customer	REGCUS	$ 1,780,463	$ 1,584,448	$ 155,269	$ 38,922	$ 1,824
68		Demand	DEM	$ -	$ -	$ -	$ -	$ -
69		Commodity	COM	$ -	$ -	$ -	$ -	$ -
70		Total House Regulators		$ 1,780,463	$ 1,584,448	$ 155,269	$ 38,922	$ 1,824
71	385	**Meas. & Reg. Sta. Equip.- Ind.**						
72		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
73		Demand	NRDEM	$ 3,163,852	$ -	$ 2,053,230	$ 1,010,891	$ 99,731
74		Commodity	COM	$ -	$ -	$ -	$ -	$ -
75		Total Meas. & Reg. Sta. Equip.- Ind.		$ 3,163,852	$ -	$ 2,053,230	$ 1,010,891	$ 99,731
76	386	**Other Prop.-Customer Premises**						
77		Customer	CUS	$ 71,409	$ 68,018	$ 2,959	$ 425	$ 6
78		Demand	DEM	$ -	$ -	$ -	$ -	$ -
79		Commodity	COM	$ -	$ -	$ -	$ -	$ -
80		Total Other Prop.- Cust. Premises		$ 71,409	$ 68,018	$ 2,959	$ 425	$ 6
81	387	**Other Equipment**						
82		Customer	CUS	$ -	$ -	$ -	$ -	$ -
83		Demand	DEM	$ -	$ -	$ -	$ -	$ -
84		Commodity	COM	$ -	$ -	$ -	$ -	$ -
85		Total Other Equipment		$ -	$ -	$ -	$ -	$ -
86		**Total Distribution Plant**						
87		Customer		$ 72,305,940	$ 68,098,067	$ 3,592,338	$ 597,259	$ 18,277
88		Demand		$ 17,941,297	$ 11,450,352	$ 4,212,399	$ 2,073,939	$ 204,608
89		Commodity		$ 277,837	$ 158,130	$ 94,647	$ 17,400	$ 7,660
90		Total Distribution Plant		$ 90,525,075	$ 79,706,548	$ 7,899,383	$ 2,688,598	$ 230,545
91		**Total General Plant**						
92		Customer	CUS	$ 12,067,170	$ 11,494,251	$ 500,007	$ 71,825	$ 1,086
93		Demand	DEM	$ 1,908,675	$ 1,478,943	$ 278,881	$ 137,305	$ 13,546
94		Commodity	COM	$ 43,887	$ 24,978	$ 14,950	$ 2,749	$ 1,210
95		Total General Plant		$ 14,019,732	$ 12,998,172	$ 793,839	$ 211,879	$ 15,842
96		**Total Plant in Service**						
97		Customer		$ 84,381,882	$ 79,600,673	$ 4,092,709	$ 669,136	$ 19,364

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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
98		Demand		$ 19,852,036	$ 12,930,894	$ 4,491,581	$ 2,211,392	$ 218,169
99		Commodity		$ 321,758	$ 183,127	$ 109,608	$ 20,151	$ 8,871
100		Total Plant in Service		$ 104,555,676	$ 92,714,694	$ 8,693,898	$ 2,900,679	$ 246,404
101		**Depreciation & Amort. Reserve**						
102		**Intangible Plant**						
103		Customer	CUS	$ (10,377)	$ (9,885)	$ (430)	$ (62)	$ (1)
104		Demand	DEM	$ (2,441)	$ (1,892)	$ (357)	$ (176)	$ (17)
105		Commodity	COM	$ (40)	$ (23)	$ (13)	$ (2)	$ (1)
106		Total Intangible Plant		$ (12,858)	$ (11,799)	$ (800)	$ (240)	$ (19)
107		**Transmission Plant**						
108		Customer	CUS	$ -	$ -	$ -	$ -	$ -
109		Demand	DEM	$ -	$ -	$ -	$ -	$ -
110		Commodity	COM	$ -	$ -	$ -	$ -	$ -
111		Total Transmission Plant		$ -	$ -	$ -	$ -	$ -
112		**Distribution Plant**						
113		Customer	DISPLTCUS	$ (16,817,051)	$ (15,838,376)	$ (835,513)	$ (4,251)	$ (138,912)
114		Demand	DISPLTDEM	$ (4,529,610)	$ (2,890,851)	$ (1,063,497)	$ (51,657)	$ (523,604)
115		Commodity	COM	$ 34,376	$ 19,565	$ 11,711	$ 2,153	$ 948
116		Total Distribution Plant		$ (21,312,284)	$ (18,709,662)	$ (1,887,299)	$ (53,755)	$ (661,568)
117		**General Plant**						
118		Customer	CUS	$ (4,377,346)	$ (4,169,520)	$ (181,377)	$ (26,055)	$ (394)
119		Demand	DEM	$ (753,877)	$ (584,144)	$ (110,151)	$ (54,232)	$ (5,350)
120		Commodity	COM	$ (6,465)	$ (3,679)	$ (2,202)	$ (405)	$ (178)
121		Total General Plant		$ (5,137,687)	$ (4,757,344)	$ (293,730)	$ (80,691)	$ (5,923)
122		**Total Depr. & Amort. Reserve**						
123		Customer		$ (21,204,774)	$ (20,017,781)	$ (1,017,320)	$ (30,367)	$ (139,306)
124		Demand		$ (5,285,928)	$ (3,476,887)	$ (1,174,005)	$ (106,065)	$ (528,972)
125		Commodity		$ 27,872	$ 15,863	$ 9,495	$ 1,746	$ 768
126		Total Depr. & Amortization Reserve		$ (26,462,830)	$ (23,478,805)	$ (2,181,830)	$ (134,686)	$ (667,510)
127		**Net Plant in Service**						
128		Customer		$ 63,177,108	$ 59,582,892	$ 3,075,389	$ 638,769	$ (119,943)
129		Demand		$ 14,566,108	$ 9,454,006	$ 3,317,576	$ 2,105,328	$ (310,803)
130		Commodity		$ 349,630	$ 198,991	$ 119,103	$ 21,897	$ 9,640
131		Total Net Plant in Service		$ 78,092,846	$ 69,235,889	$ 6,512,069	$ 2,765,993	$ (421,106)
132		**Customer Deposits**						

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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
133		Customer	DEPCUS	$ (1,234,179)	$ (810,705)	$ (421,238)	$ (248)	$ (1,987)
134		Demand	DEM	$ -	$ -	$ -	$ -	$ -
135		Commodity	COM	$ -	$ -	$ -	$ -	$ -
136		Total Customer Deposits		$ (1,234,179)	$ (810,705)	$ (421,238)	$ (248)	$ (1,987)
137		**Customer Advances**						
138		Customer	MSCUS	$ (427,780)	$ (405,788)	$ (19,194)	$ (2,744)	$ (54)
139		Demand	DEM	$ (89,758)	$ (69,549)	$ (13,115)	$ (6,457)	$ (637)
140		Commodity	COM	$ -	$ -	$ -	$ -	$ -
141		Total Customer Advances		$ (517,538)	$ (475,337)	$ (32,309)	$ (9,200)	$ (691)
142		**Accum. Deferred Income Taxes**						
143		Customer	TPLTCUS	$ (14,846,921)	$ (14,005,671)	$ (720,109)	$ (3,407)	$ (117,734)
144		Demand	TPLTDEM	$ (3,492,949)	$ (2,275,180)	$ (790,290)	$ (38,387)	$ (389,093)
145		Commodity	COM	$ (56,613)	$ (32,221)	$ (19,286)	$ (3,546)	$ (1,561)
146		Total Accum. Deferred Inc. Taxes		$ (18,396,483)	$ (16,313,072)	$ (1,529,684)	$ (45,339)	$ (508,387)
147		**Materials and Supplies**						
148		Customer	TPLTCUS	$ 492,029	$ 464,149	$ 23,864	$ 113	$ 3,902
149		Demand	TPLTDEM	$ 115,757	$ 75,400	$ 26,190	$ 1,272	$ 12,895
150		Commodity	COM	$ 1,876	$ 1,068	$ 639	$ 117	$ 52
151		Total Materials and Supplies		$ 609,661	$ 540,617	$ 50,694	$ 1,503	$ 16,848
152		**Prepayments**						
153		Customer	OPEXPCUS	$ 306,328	$ 288,680	$ 14,993	$ 478	$ 2,177
154		Demand	OPEXPDEM	$ 64,089	$ 41,482	$ 14,671	$ 1,290	$ 6,646
155		Commodity	COM	$ 3,141	$ 1,787	$ 1,070	$ 197	$ 87
156		Total Prepayments		$ 373,558	$ 331,950	$ 30,734	$ 1,964	$ 8,910
157		**Pension & FAS 106 Reg. Asset**						
158		Customer	OPEXPCUS	$ 2,826,175	$ 2,663,359	$ 138,324	$ 4,410	$ 20,082
159		Demand	OPEXPDEM	$ 591,286	$ 382,711	$ 135,358	$ 11,899	$ 61,318
160		Commodity	COM	$ 28,975	$ 16,491	$ 9,870	$ 1,815	$ 799
161		Total Pen. & FAS 106 Reg. Asset		$ 3,446,436	$ 3,062,562	$ 283,553	$ 18,123	$ 82,199
162		**DIMP Deferrals**						
163		Customer	TPLTCUS	$ 49,690	$ 46,874	$ 2,410	$ 11	$ 394
164		Demand	TPLTDEM	$ 10,396	$ 6,772	$ 2,352	$ 114	$ 1,158
165		Commodity	COM	$ 509	$ 290	$ 174	$ 32	$ 14
166		Total DIMP Deferrals		$ 60,595	$ 53,936	$ 4,936	$ 158	$ 1,566
167		**Cash Working Capital**						

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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
168		Customer	OPEXPCUS	$ (578,300)	$ (544,984)	$ (28,304)	$ (902)	$ (4,109)
169		Demand	OPEXPDEM	$ (120,991)	$ (78,312)	$ (27,697)	$ (2,435)	$ (12,547)
170		Commodity	COM	$ (5,929)	$ (3,374)	$ (2,020)	$ (371)	$ (163)
171		Total Cash Working Capital		$ (705,220)	$ (626,670)	$ (58,021)	$ (3,708)	$ (16,820)
172		**Total Rate Base**						
173		Customer		$ 49,764,149	$ 47,278,807	$ 2,066,135	$ 636,480	$ (217,273)
174		Demand		$ 11,643,939	$ 7,537,331	$ 2,665,046	$ 2,072,624	$ (631,062)
175		Commodity		$ 321,589	$ 183,031	$ 109,551	$ 20,140	$ 8,867
176		Total Rate Base		$ 61,729,677	$ 54,999,169	$ 4,840,732	$ 2,729,244	$ (839,469)

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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	850-66	Transmission Expense						
3		Customer	CUS	$ -	$ -	$ -	$ -	$ -
4		Demand	DEM	$ 98,226	$ 76,110	$ 14,352	$ 7,066	$ 697
5		Commodity	COM	$ -	$ -	$ -	$ -	$ -
6		Total Transmission Expense		$ 98,226	$ 76,110	$ 14,352	$ 7,066	$ 697
7	870	**Operation Supervision & Engineering**						
8		Customer	871-879CUS	$ 165,872	$ 154,336	$ 9,581	$ 76	$ 1,880
9		Demand	DEM	$ 28,550	$ 22,122	$ 4,172	$ 2,054	$ 203
10		Commodity	COM	$ 4,643	$ 2,643	$ 1,582	$ 291	$ 128
11		Total Supervision & Engineering		$ 199,066	$ 179,101	$ 15,334	$ 2,420	$ 2,210
12	870	**Odorization**						
13		Customer	CUS	$ -	$ -	$ -	$ -	$ -
14		Demand	DEM	$ -	$ -	$ -	$ -	$ -
15		Commodity	COM	$ 814	$ 463	$ 277	$ 51	$ 22
16		Total Odorization		$ 814	$ 463	$ 277	$ 51	$ 22
17	871	**Distribution Load Dispatch**						
18		Customer	CUS	$ -	$ -	$ -	$ -	$ -
19		Demand	DEM	$ -	$ -	$ -	$ -	$ -
20		Commodity	COM	$ 37,648	$ 21,427	$ 12,825	$ 2,358	$ 1,038
21		Total Distribution Load Dispatch		$ 37,648	$ 21,427	$ 12,825	$ 2,358	$ 1,038
22	874	**Mains and Services Expenses**						
23		Customer	MSCUS	$ 682,807	$ 647,704	$ 30,637	$ 4,379	$ 87
24		Demand	DEM	$ 143,268	$ 111,011	$ 20,933	$ 10,306	$ 1,017
25		Commodity	COM	$ -	$ -	$ -	$ -	$ -
26		Total Mains & Services		$ 826,074	$ 758,715	$ 51,570	$ 14,685	$ 1,104
27	874	**Odorization**						
28		Customer	CUS	$ -	$ -	$ -	$ -	$ -

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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)
29		Demand	DEM	$ -	$ -	$ -	$ -	$ -
30		Commodity	COM	$ 657	$ 374	$ 224	$ 41	$ 18
31		Total Odorization		$ 657	$ 374	$ 224	$ 41	$ 18
32	875	**Meas. & Reg. Station - General**						
33		Customer	CUS	$ -	$ -	$ -	$ -	$ -
34		Demand	DEM	$ 81,596	$ 63,225	$ 11,922	$ 5,870	$ 579
35		Commodity	COM	$ -	$ -	$ -	$ -	$ -
36		Total Meas. & Reg. Station - General		$ 81,596	$ 63,225	$ 11,922	$ 5,870	$ 579
37	875	**Odorization**						
38		Customer	CUS	$ -	$ -	$ -	$ -	$ -
39		Demand	DEM	$ -	$ -	$ -	$ -	$ -
40		Commodity	COM	$ 7,895	$ 4,493	$ 2,689	$ 494	$ 218
41		Total Odorization		$ 7,895	$ 4,493	$ 2,689	$ 494	$ 218
42	876	**Meas. & Reg. Stat. - Industrial**						
43		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
44		Demand	NRDEM	$ 6,091	$ -	$ 3,953	$ 1,946	$ 192
45		Commodity	COM	$ -	$ -	$ -	$ -	$ -
46		Total Meas. & Reg. Stat. - Industrial		$ 6,091	$ -	$ 3,953	$ 1,946	$ 192
47	877	**Meas. & Reg. Stat.- City Gate**						
48		Customer	CUS	$ -	$ -	$ -	$ -	$ -
49		Demand	DEM	$ 536	$ 415	$ 78	$ 39	$ 4
50		Commodity	COM	$ -	$ -	$ -	$ -	$ -
51		Total Meas. & Reg. Stat. - City Gate		$ 536	$ 415	$ 78	$ 39	$ 4
52	878	**Meter & House Reg. Expense**						
53		Customer	MTRGCUS	$ 683,077	$ 622,891	$ 48,460	$ 11,182	$ 544
54		Demand	DEM	$ -	$ -	$ -	$ -	$ -
55		Commodity	COM	$ -	$ -	$ -	$ -	$ -
56		Total Meter & House Reg. Expense		$ 683,077	$ 622,891	$ 48,460	$ 11,182	$ 544

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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)
57	879	**Customer Installation Expense**						
58		Customer	METCUS	$ (20,955)	$ (19,206)	$ (1,414)	$ (319)	$ (16)
59		Demand	DEM	$ -	$ -	$ -	$ -	$ -
60		Commodity	COM	$ -	$ -	$ -	$ -	$ -
61		Total Customer Install. Expense		$ (20,955)	$ (19,206)	$ (1,414)	$ (319)	$ (16)
62	880	**Other Expenses**						
63		Customer	871-879CUS	$ 219,569	$ 204,298	$ 12,682	$ 100	$ 2,488
64		Demand	DEM	$ -	$ -	$ -	$ -	$ -
65		Commodity	COM	$ -	$ -	$ -	$ -	$ -
66		Total Other Expenses		$ 219,569	$ 204,298	$ 12,682	$ 100	$ 2,488
67	880	**Odorization**						
68		Customer	CUS	$ -	$ -	$ -	$ -	$ -
69		Demand	DEM	$ -	$ -	$ -	$ -	$ -
70		Commodity	COM	$ -	$ -	$ -	$ -	$ -
71		Total Odorization		$ -	$ -	$ -	$ -	$ -
72	881	**Rents**						
73		Customer	871-879CUS	$ 3,379	$ 3,144	$ 195	$ 2	$ 38
74		Demand	DEM	$ 582	$ 451	$ 85	$ 42	$ 4
75		Commodity	COM	$ 95	$ 54	$ 32	$ 6	$ 3
76		Total Rents		$ 4,055	$ 3,648	$ 312	$ 49	$ 45
77		**Total Distr. & Trans. Op. Expense**						
78		Customer		$ 1,733,749	$ 1,613,167	$ 100,141	$ 15,420	$ 5,022
79		Demand		$ 358,849	$ 273,335	$ 55,495	$ 27,323	$ 2,696
80		Commodity		$ 51,751	$ 29,454	$ 17,629	$ 3,241	$ 1,427
81		Total Distr. & Trans. Operations Exp.		$ 2,144,348	$ 1,915,956	$ 173,265	$ 45,984	$ 9,144
82		**Distr. Maintenance Expenses**						
83	886	**Supervision and Engineering**						
84		Customer	887-893CUS	$ 42	$ 40	$ 2	$ 0	$ 0

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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)
85		Demand	887-893DEM	$ 30	$ 18	$ 8	$ 0	$ 4
86		Commodity	COM	$ -	$ -	$ -	$ -	$ -
87		Total Supervision and Engineering		$ 72	$ 58	$ 10	$ 0	$ 4
88	886	**Structures and Improvements**						
89		Customer	887-893CUS	$ 71,104	$ 67,623	$ 3,038	$ 7	$ 436
90		Demand	887-893DEM	$ 49,630	$ 29,545	$ 13,034	$ 633	$ 6,417
91		Commodity	COM	$ -	$ -	$ -	$ -	$ -
92		Total Structures and Improvements		$ 120,734	$ 97,168	$ 16,072	$ 640	$ 6,853
93	887	**Mains**						
94		Customer	CUS	$ 728,730	$ 694,132	$ 30,195	$ 4,337	$ 66
95		Demand	DEM	$ 354,741	$ 274,872	$ 51,832	$ 25,519	$ 2,518
96		Commodity	COM	$ -	$ -	$ -	$ -	$ -
97		Total Mains		$ 1,083,472	$ 969,004	$ 82,027	$ 29,857	$ 2,583
98	889	**Meas. & Reg. Sta. Equip. - General**						
99		Customer	CUS	$ -	$ -	$ -	$ -	$ -
100		Demand	DEM	$ 142,764	$ 110,621	$ 20,860	$ 10,270	$ 1,013
101		Commodity	COM	$ -	$ -	$ -	$ -	$ -
102		Total Meas. & Reg. Sta. Equip. - Gen.		$ 142,764	$ 110,621	$ 20,860	$ 10,270	$ 1,013
103	890	**Meas. & Reg. Sta. Equip. - Industrial**						
104		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
105		Demand	NRDEM	$ 150,045	$ -	$ 97,374	$ 47,941	$ 4,730
106		Commodity	COM	$ -	$ -	$ -	$ -	$ -
107		Total Meas. & Reg. Sta. Eq.- Industrial		$ 150,045	$ -	$ 97,374	$ 47,941	$ 4,730
108	891	**Meas. & Reg. Sta. Eq.- City Gate**						
109		Customer	CUS	$ -	$ -	$ -	$ -	$ -
110		Demand	DEM	$ 11	$ 8	$ 2	$ 1	$ 0
111		Commodity	COM	$ -	$ -	$ -	$ -	$ -
112		Total Meas. & Reg. Sta. Eq.- City Gate		$ 11	$ 8	$ 2	$ 1	$ 0

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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)
113	892	**Services**						
114		Customer	SERCUS	$ 199,027	$ 188,203	$ 9,448	$ 1,346	$ 31
115		Demand	DEM	$ -	$ -	$ -	$ -	$ -
116		Commodity	COM	$ -	$ -	$ -	$ -	$ -
117		Total Services		$ 199,027	$ 188,203	$ 9,448	$ 1,346	$ 31
118	893	**Meters & House Regulators**						
119		Customer	MTRGCUS	$ -	$ -	$ -	$ -	$ -
120		Demand	DEM	$ -	$ -	$ -	$ -	$ -
121		Commodity	COM	$ -	$ -	$ -	$ -	$ -
122		Total Meters & House Regulators		$ -	$ -	$ -	$ -	$ -
123	894	**Other Equipment**						
124		Customer	CUS	$ -	$ -	$ -	$ -	$ -
125		Demand	DEM	$ -	$ -	$ -	$ -	$ -
126		Commodity	COM	$ -	$ -	$ -	$ -	$ -
127		Total Other Equipment		$ -	$ -	$ -	$ -	$ -
128		**Total Distr. Maintenance Expense**						
129		Customer		$ 998,904	$ 949,997	$ 42,683	$ 5,691	$ 532
130		Demand		$ 697,221	$ 415,065	$ 183,109	$ 84,365	$ 14,682
131		Commodity		$ -	$ -	$ -	$ -	$ -
132		Total Distr. Maintenance Expense		$ 1,696,125	$ 1,365,062	$ 225,793	$ 90,056	$ 15,214
133		**Total Oper. & Maint. Expense**						
134		Customer		$ 2,732,653	$ 2,563,164	$ 142,824	$ 21,111	$ 5,554
135		Demand		$ 1,056,070	$ 688,400	$ 238,605	$ 111,687	$ 17,377
136		Commodity		$ 51,751	$ 29,454	$ 17,629	$ 3,241	$ 1,427
137		Total Operations & Maint. Expense		$ 3,840,473	$ 3,281,018	$ 399,058	$ 136,039	$ 24,358
138		**Customer Accounts Expense**						
139	901	**Supervision**						
140		Customer	902-904CUS	$ 22,354	$ 21,408	$ 826	$ 4	$ 116

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
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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)
141		Demand	DEM	$ -	$ -	$ -	$ -	$ -
142		Commodity	COM	$ -	$ -	$ -	$ -	$ -
143		Total Supervision		$ 22,354	$ 21,408	$ 826	$ 4	$ 116
144	902	**Meter Reading Expense**						
145		Customer	METCUS	$ 231,223	$ 211,927	$ 15,607	$ 3,516	$ 173
146		Demand	DEM	$ -	$ -	$ -	$ -	$ -
147		Commodity	COM	$ -	$ -	$ -	$ -	$ -
148		Total Meter Reading Expense		$ 231,223	$ 211,927	$ 15,607	$ 3,516	$ 173
149	903	**Customer Accounting**						
150		Customer	903CUS	$ 667,360	$ 649,330	$ 16,282	$ 1,727	$ 20
151		Demand	DEM	$ -	$ -	$ -	$ -	$ -
152		Commodity	COM	$ -	$ -	$ -	$ -	$ -
153		Total Customer Accounting		$ 667,360	$ 649,330	$ 16,282	$ 1,727	$ 20
154	904	**Bad Debt Expense**						
155		Customer	904CUS	$ 111,129	$ 105,712	$ 5,416	$ -	$ -
156		Demand	DEM	$ -	$ -	$ -	$ -	$ -
157		Commodity	COM	$ -	$ -	$ -	$ -	$ -
158		Total Bad Debt Expense		$ 111,129	$ 105,712	$ 5,416	$ -	$ -
159	905	**Miscellaneous Customer Accounts**						
160		Customer	902-904CUS	$ 61,644	$ 59,034	$ 2,278	$ 12	$ 320
161		Demand	DEM	$ -	$ -	$ -	$ -	$ -
162		Commodity	COM	$ -	$ -	$ -	$ -	$ -
163		Total Misc. Customer Accounts		$ 61,644	$ 59,034	$ 2,278	$ 12	$ 320
164	907-910	**Customer Service Expense**						
165		Customer	CUS	$ 129,158	$ 123,026	$ 5,352	$ 769	$ 12
166		Demand	DEM	$ -	$ -	$ -	$ -	$ -
167		Commodity	COM	$ -	$ -	$ -	$ -	$ -
168		Total Customer Service Expense		$ 129,158	$ 123,026	$ 5,352	$ 769	$ 12

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
169		**Sales and Advertising Expense**						
170	912	**Demonstrating and Selling**						
171		Customer	CUS	$ -	$ -	$ -	$ -	$ -
172		Demand	DEM	$ -	$ -	$ -	$ -	$ -
173		Commodity	COM	$ -	$ -	$ -	$ -	$ -
174		Total Demon. and Selling Expense		$ -	$ -	$ -	$ -	$ -
175	913	**Advertising**						
176		Customer	CUS	$ 305	$ 291	$ 13	$ 2	$ 0
177		Demand	DEM	$ -	$ -	$ -	$ -	$ -
178		Commodity	COM	$ -	$ -	$ -	$ -	$ -
179		Total Advertising		$ 305	$ 291	$ 13	$ 2	$ 0
180		**Administrative & General Exp.**						
181	921-32	**Administrative & General Exp.**						
182		Customer	OPEXPCUS	$ 3,322,095	$ 3,130,710	$ 162,597	$ 5,183	$ 23,606
183		Demand	OPEXPDEM	$ 466,602	$ 302,009	$ 106,815	$ 9,390	$ 48,388
184		Commodity	COM	$ 22,865	$ 13,014	$ 7,789	$ 1,432	$ 630
185		Total Administrative & General Exp.		$ 3,811,562	$ 3,445,733	$ 277,201	$ 16,005	$ 72,624
186		**Depreciation & Amort. Expense**						
187	301-03	**Intangible Plant**						
188		Customer	CUS	$ -	$ -	$ -	$ -	$ -
189		Demand	DEM	$ -	$ -	$ -	$ -	$ -
190		Commodity	COM	$ -	$ -	$ -	$ -	$ -
191		Total Intangible Plant		$ -	$ -	$ -	$ -	$ -
192	366	**Meas. and Reg. Station Structures**						
193		Customer	CUS	$ -	$ -	$ -	$ -	$ -
194		Demand	DEM	$ -	$ -	$ -	$ -	$ -
195		Commodity	COM	$ -	$ -	$ -	$ -	$ -
196		Total Measuring and Reg. Stat. Struct.		$ -	$ -	$ -	$ -	$ -

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
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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)
197	367	**Transmission Mains**						
198		Customer	CUS	$ -	$ -	$ -	$ -	$ -
199		Demand	DEM	$ -	$ -	$ -	$ -	$ -
200		Commodity	COM	$ -	$ -	$ -	$ -	$ -
201		Total Transmission Mains		$ -	$ -	$ -	$ -	$ -
202	368	**Compression Station Equipment**						
203		Customer	CUS	$ -	$ -	$ -	$ -	$ -
204		Demand	DEM	$ -	$ -	$ -	$ -	$ -
205		Commodity	COM	$ -	$ -	$ -	$ -	$ -
206		Total Compression Sta. Equipment		$ -	$ -	$ -	$ -	$ -
207	369	**Meas. & Reg. Station Equipment**						
208		Customer	CUS	$ -	$ -	$ -	$ -	$ -
209		Demand	DEM	$ -	$ -	$ -	$ -	$ -
210		Commodity	COM	$ -	$ -	$ -	$ -	$ -
211		Total Meas. & Reg. Stat. Equipment		$ -	$ -	$ -	$ -	$ -
212	371	**Other Equipment**						
213		Customer	CUS	$ -	$ -	$ -	$ -	$ -
214		Demand	DEM	$ -	$ -	$ -	$ -	$ -
215		Commodity	COM	$ -	$ -	$ -	$ -	$ -
216		Total Other Equipment		$ -	$ -	$ -	$ -	$ -
217	375	**Structures and Improvements**						
218		Customer	376-379CUS	$ 339	$ 323	$ 14	$ 0	$ 2
219		Demand	DEM	$ 199	$ 154	$ 29	$ 14	$ 1
220		Commodity	COM	$ 3	$ 2	$ 1	$ 0	$ 0
221		Total Structures and Improvements		$ 540	$ 478	$ 44	$ 15	$ 4
222	376	**Distribution Mains**						
223		Customer	CUS	$ 537,397	$ 511,883	$ 22,267	$ 3,199	$ 48
224		Demand	DEM	$ 261,602	$ 202,703	$ 38,223	$ 18,819	$ 1,857

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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)
225		Commodity	COM	$ -	$ -	$ -	$ -	$ -
226		Total Distribution Mains		$ 798,999	$ 714,586	$ 60,491	$ 22,018	$ 1,905
227	377	**Compressor Station Equipment**						
228		Customer	CUS	$ -	$ -	$ -	$ -	$ -
229		Demand	DEM	$ -	$ -	$ -	$ -	$ -
230		Commodity	COM	$ -	$ -	$ -	$ -	$ -
231		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -
232	378	**Meas. & Reg. Sta. Equip. - General**						
233		Customer	CUS	$ -	$ -	$ -	$ -	$ -
234		Demand	DEM	$ 34,024	$ 26,364	$ 4,971	$ 2,448	$ 241
235		Commodity	COM	$ -	$ -	$ -	$ -	$ -
236		Total Meas. & Reg. Sta. Eq.- General		$ 34,024	$ 26,364	$ 4,971	$ 2,448	$ 241
237	378	**Odorization Tank**						
238		Customer	CUS	$ -	$ -	$ -	$ -	$ -
239		Demand	DEM	$ -	$ -	$ -	$ -	$ -
240		Commodity	COM	$ 1,277	$ 727	$ 435	$ 80	$ 35
241		Total Odorization Tank		$ 1,277	$ 727	$ 435	$ 80	$ 35
242	379	**Meas.& Reg. Sta. Equip.- City Gate**						
243		Customer	CUS	$ -	$ -	$ -	$ -	$ -
244		Demand	DEM	$ 17,728	$ 13,736	$ 2,590	$ 1,275	$ 126
245		Commodity	COM	$ -	$ -	$ -	$ -	$ -
246		Total Meas. & Reg. Sta. Eq.- City Gate		$ 17,728	$ 13,736	$ 2,590	$ 1,275	$ 126
247	379	**Odorization Tank**						
248		Customer	CUS	$ -	$ -	$ -	$ -	$ -
249		Demand	DEM	$ -	$ -	$ -	$ -	$ -
250		Commodity	COM	$ 3,982	$ 2,266	$ 1,356	$ 249	$ 110
251		Total Odorization Tank		$ 3,982	$ 2,266	$ 1,356	$ 249	$ 110
252	380	**Services**						

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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)
253		Customer	SERCUS	$ 900,559	$ 851,578	$ 42,751	$ 6,090	$ 140
254		Demand	DEM	$ -	$ -	$ -	$ -	$ -
255		Commodity	COM	$ -	$ -	$ -	$ -	$ -
256		Total Services		$ 900,559	$ 851,578	$ 42,751	$ 6,090	$ 140
257	381	**Meters**						
258		Customer	METCUS	$ 541,481	$ 496,293	$ 36,549	$ 8,234	$ 405
259		Demand	DEM	$ -	$ -	$ -	$ -	$ -
260		Commodity	COM	$ -	$ -	$ -	$ -	$ -
261		Total Meters		$ 541,481	$ 496,293	$ 36,549	$ 8,234	$ 405
262	382	**Meter Installations**						
263		Customer	CUS	$ 60	$ 58	$ 3	$ 0	$ 0
264		Demand	DEM	$ -	$ -	$ -	$ -	$ -
265		Commodity	COM	$ -	$ -	$ -	$ -	$ -
266		Total Meter Installations		$ 60	$ 58	$ 3	$ 0	$ 0
267	383	**House Regulators**						
268		Customer	REGCUS	$ 51,277	$ 45,632	$ 4,472	$ 1,121	$ 53
269		Demand	DEM	$ -	$ -	$ -	$ -	$ -
270		Commodity	COM	$ -	$ -	$ -	$ -	$ -
271		Total House Regulators		$ 51,277	$ 45,632	$ 4,472	$ 1,121	$ 53
272	385	**Meas. & Reg. Sta. Eq. - Industrial**						
273		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
274		Demand	NRDEM	$ 68,656	$ -	$ 44,555	$ 21,936	$ 2,164
275		Commodity	COM	$ -	$ -	$ -	$ -	$ -
276		Total Meas. & Reg. Stat. Eq.- Indus.		$ 68,656	$ -	$ 44,555	$ 21,936	$ 2,164
277	386	**Other Prop.- Customer Premises**						
278		Customer	CUS	$ 5,220	$ 4,972	$ 216	$ 31	$ 0
279		Demand	DEM	$ -	$ -	$ -	$ -	$ -
280		Commodity	COM	$ -	$ -	$ -	$ -	$ -

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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)
281		Total Other Prop. - Customer Premises		$ 5,220	$ 4,972	$ 216	$ 31	$ 0
282	387	**Other Equipment**						
283		Customer	CUS	$ -	$ -	$ -	$ -	$ -
284		Demand	DEM	$ -	$ -	$ -	$ -	$ -
285		Commodity	COM	$ -	$ -	$ -	$ -	$ -
286		Total Other Equipment		$ -	$ -	$ -	$ -	$ -
287	389-98	**General Plant**						
288		Customer	GENPTCUS	$ 674,148	$ 637,535	$ 31,478	$ 1,563	$ 3,572
289		Demand	DISPLTDEM	$ 75,437	$ 48,144	$ 17,712	$ 860	$ 8,720
290		Commodity	COM	$ 2,123	$ 1,209	$ 723	$ 133	$ 59
291		Total General Plant		$ 751,708	$ 686,889	$ 49,913	$ 2,557	$ 12,350
292	4073	**Pension & FAS 106 Amort. Expense**						
293		Customer	CUS	$ 9,472	$ 9,023	$ 392	$ 56	$ 1
294		Demand	DEM	$ 1,982	$ 1,536	$ 290	$ 143	$ 14
295		Commodity	COM	$ 97	$ 55	$ 33	$ 6	$ 3
296		Total Pension & FAS 106 Amort. Exp.		$ 11,551	$ 10,613	$ 715	$ 205	$ 18
297		**Total Depreciation & Amort. Exp.**						
298		Customer		$ 2,719,955	$ 2,557,297	$ 138,142	$ 20,295	$ 4,221
299		Demand		$ 459,626	$ 292,637	$ 108,370	$ 45,495	$ 13,124
300		Commodity		$ 7,482	$ 4,259	$ 2,549	$ 469	$ 206
301		Total Depreciation & Amort. Expense		$ 3,187,063	$ 2,854,193	$ 249,061	$ 66,259	$ 17,551
302		**Taxes Other Than Income**						
303	4081	**Payroll and Other Taxes**						
304		Customer	OPEXPCUS	$ 361,181	$ 340,374	$ 17,678	$ 564	$ 2,566
305		Demand	OPEXPDEM	$ 75,566	$ 48,910	$ 17,299	$ 1,521	$ 7,836
306		Commodity	COM	$ 3,703	$ 2,108	$ 1,261	$ 232	$ 102
307		Total Payroll and Other Taxes		$ 440,450	$ 391,391	$ 36,238	$ 2,316	$ 10,505
308		**Ad Valorem Taxes**						

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ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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)
309		Customer	CUS	$ 551,643	$ 525,452	$ 22,858	$ 3,283	$ 50
310		Demand	DEM	$ 129,782	$ 100,562	$ 18,963	$ 9,336	$ 921
311		Commodity	COM	$ 2,103	$ 1,197	$ 717	$ 132	$ 58
312		Total Ad Valorem Taxes		$ 683,528	$ 627,211	$ 42,537	$ 12,751	$ 1,029
313		**Revenue Related Taxes**						
314		Customer	TOTREVCUS	$ 8,940	$ 6,524	$ 1,889	$ 438	$ 89
315		Demand	DEM	$ -	$ -	$ -	$ -	$ -
316		Commodity	COM	$ -	$ -	$ -	$ -	$ -
317		Total Revenue Related Taxes		$ 8,940	$ 6,524	$ 1,889	$ 438	$ 89
318		**Total Taxes Other Than Income**						
319		Customer		$ 921,764	$ 872,350	$ 42,424	$ 4,285	$ 2,705
320		Demand		$ 205,347	$ 149,472	$ 36,261	$ 10,857	$ 8,757
321		Commodity		$ 5,806	$ 3,305	$ 1,978	$ 364	$ 160
322		Total Taxes Other Than Income		$ 1,132,918	$ 1,025,127	$ 80,663	$ 15,505	$ 11,622
323		**Interest on Customer Deposits**						
324		Customer	DEPCUS	$ 23,696	$ 15,566	$ 8,088	$ 5	$ 38
325		Demand	DEM	$ -	$ -	$ -	$ -	$ -
326		Commodity	COM	$ -	$ -	$ -	$ -	$ -
327		Total Interest on Cust. Deposits		$ 23,696	$ 15,566	$ 8,088	$ 5	$ 38
328		**Required Return**						
329		Customer	CUS	$ 3,944,581	$ 3,757,302	$ 163,445	$ 23,479	$ 355
330		Demand	DEM	$ 922,963	$ 715,161	$ 134,856	$ 66,395	$ 6,550
331		Commodity	COM	$ 25,491	$ 14,508	$ 8,684	$ 1,596	$ 703
332		Total Required Return		$ 4,893,035	$ 4,486,971	$ 306,985	$ 91,470	$ 7,608
333		**Income Taxes**						
334		Customer	CUS	$ 826,403	$ 787,167	$ 34,242	$ 4,919	$ 74
335		Demand	DEM	$ 193,364	$ 149,829	$ 28,253	$ 13,910	$ 1,372
336		Commodity	COM	$ 5,340	$ 3,039	$ 1,819	$ 334	$ 147

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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)
337		Total Income Taxes		$ 1,025,107	$ 940,035	$ 64,314	$ 19,163	$ 1,594
338		**Total Cost of Service Before**						
339		**Revenue Credits**						
340		Customer		$ 15,714,320	$ 14,854,285	$ 737,535	$ 85,306	$ 37,194
341		Demand		$ 3,303,972	$ 2,297,508	$ 653,160	$ 257,735	$ 95,569
342		Commodity		$ 118,736	$ 67,578	$ 40,448	$ 7,436	$ 3,274
343		**Total Cost of Service Before Revenue Credits**		$ 19,137,027	$ 17,219,371	$ 1,431,143	$ 350,477	$ 136,037

ALLOCATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

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		533,235	507,918	22,095	48	3,174
4	**Total Customers Factor (CUS)**	**CUS**	**1.00000**	**0.95252**	**0.04144**	**0.00009**	**0.00595**
5							
6	Services Weighting			1.00000	1.15405	1.73561	1.14452
7	Weighted Customers		537,133	507,918	25,498	83	3,633
8	**Weighted Services Customer Factor (SERCUS)**	**SERCUS**	**1.00000**	**0.94561**	**0.04747**	**0.00016**	**0.00676**
9							
10	Meters Weighting			1.00000	1.69294	8.64105	2.65502
11	Weighted Customers		554,165	507,918	37,405	415	8,427
12	**Weighted Meters Customer Factor (METCUS)**	**METCUS**	**1.00000**	**0.91655**	**0.06750**	**0.00075**	**0.01521**
13							
14	Regulators Weighting			1.00000	2.25274	12.18142	3.93118
15	Weighted Customers		570,754	507,918	49,774	585	12,477
16	**Weighted Regulators Customer Factor (REGCUS)**	**REGCUS**	**1.00000**	**0.88991**	**0.08721**	**0.00102**	**0.02186**
17							
18	Meters and Regulators Weighting			1.00000	1.78843	9.24501	2.87272
19	Weighted Customers		556,995	507,918	39,515	444	9,118
20	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS)**	**MTRGCUS**	**1.00000**	**0.91189**	**0.07094**	**0.00080**	**0.01637**
21							
22	Non-Residential Customers		25,317	0	22,095	48	3,174
23	**Non-Residential Customers Factor (NRCUS)**	**NRCUS**	**1.00000**	**0.00000**	**0.87274**	**0.00190**	**0.12537**
24							
25	**Customer Cost Allocation Factors**						
26							
27	Distribution Plant Customer Costs		$ 72,305,940	$ 68,098,067	$ 3,592,338	$ 597,259	$ 18,2[illegible]

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ALLOCATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
28	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	**DISPLTCUS**	**1.00000**	**0.94180**	**0.04968**	**0.00826**	**0.00025**
29							
30	Account 376-379 Customer Costs		25,151,865	$ 23,957,717	$ 1,042,176	$ 149,707	$ 2,264
31	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	**376-379CUS**	**1.00000**	**0.95252**	**0.04144**	**0.00595**	**0.00009**
32							
33	Total Revenue (inc. cost of gas)		27,171,215	$ 19,829,796	$ 5,741,240	$ 269,721	$ 1,330,459
34	**Total Revenue (TOTREVCUS)**	**TOTREVCUS**	**1.00000**	**0.72981**	**0.21130**	**0.00993**	**0.04897**
35							
36	Mains - Customer Cost Factor		**0.43103**	**0.41056**	**0.01786**	**0.00004**	**0.00257**
37	Services - Customer Cost Factor		**0.56897**	**0.53803**	**0.02701**	**0.00009**	**0.00385**
38	**Mains & Svcs. Customer Factor (MSCUS)**	**MSCUS**	**1.00000**	**0.94859**	**0.04487**	**0.00013**	**0.00641**
39							
40	Total Plant Customer		$ 84,381,882	$ 79,600,673	$ 4,092,709	$ 669,136	$ 19,364
41	**Total Plant Factor (TPLTCUS)**	**TPLTCUS**	**1.00000**	**0.94334**	**0.04850**	**0.00793**	**0.00023**
42							
43	Account 871-879 Customer Costs		$ 1,344,929	$ 1,251,389	$ 77,683	$ 15,242	$ 615
44	**Account 871-879 Cust. Costs Factor (871-879CUS)**	**871-879CUS**	**1.00000**	**0.93045**	**0.05776**	**0.01133**	**0.00046**
45							
46	Account 887-893 Customer Costs		$ 927,758	$ 882,334	$ 39,643	$ 5,684	$ 96
47	**Account 887-893 Cust. Costs Factor (887-893CUS)**	**887-893CUS**	**1.00000**	**0.95104**	**0.04273**	**0.00613**	**0.00010**
48							
49	Account 903 Customer		$ 667,360	$ 649,330	$ 16,282	$ 20	$ 1,727
50	**Account 903 Customer Factor (903CUS)**	**903CUS**	**1.00000**	**0.97298**	**0.02440**	**0.00003**	**0.00259**
51							
52	**Customer Cost Allocation Factors**						
53							
54	Account 904 Customer		$ 111,129	$ 105,712	$ 5,416	$ -	$ -
55	**Account 904 Customer Factor (904CUS)**	**904CUS**	**1.00000**	**0.95126**	**0.04874**	**0.00000**	**0.00000**

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
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CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
56							
57	Accounts 902-904 Customer		$ 1,009,711	$ 966,969	$ 37,306	$ 5,243	$ 193
58	**Accts. 902-904 Customer Factor (902-904CUS)**	**902-904CUS**	**1.00000**	**0.95767**	**0.03695**	**0.00519**	**0.00019**
59							
60	Operating Expense Customer		$ 6,675,780	$ 6,291,189	$ 326,739	$ 47,436	$ 10,416
61	**Operating Exp. Customer Factor (OPEXPCUS)**	**OPEXPCUS**	**1.00000**	**0.94239**	**0.04894**	**0.00711**	**0.00156**
62							
63	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 7,692,227	$ 7,244,575	$ 382,169	$ 63,539	$ 1,944
64	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 4,374,943	$ 4,167,232	$ 181,277	$ 394	$ 26,040
65	Total General Plant Customer Costs		$ 12,067,170	$ 11,411,807	$ 563,446	$ 63,933	$ 27,985
66	**General Plant Customer Factor (GENPTCUS)**	**GENPTCUS**	**1.00000**	**0.94569**	**0.04669**	**0.00530**	**0.00232**
67							
68	Customer Deposits		$ (1,234,179)	$ (810,705)	$ (421,238)	$ (1,987)	$ (248)
69	**Customer Deposits Factor (DEPCUS)**	**DEPCUS**	**1.00000**	**0.65688**	**0.34131**	**0.00161**	**0.00020**
70							
71	**Demand Cost Allocation Factors**						
72							
73	System Demand						
74	**System Demand Factor (DEM)**	**DEM**	**1.00000**	**0.77485**	**0.14611**	**0.00710**	**0.07194**
75							
76	Non-Residential Demand						
77	**Non-Residential Demand Factor (NRDEM)**	**NRDEM**	**1.00000**	**0.00000**	**0.64897**	**0.03152**	**0.31951**
78							
79	Distribution Plant Demand		$ 17,941,297	$ 11,450,352	$ 4,212,399	$ 2,073,939	$ 204,608
80	**Distribution Plant Demand Factor (DISPLTDEM)**	**DISPLTDEM**	**1.00000**	**0.63821**	**0.23479**	**0.11560**	**0.01140**
81							
82	**Demand Cost Allocation Factors**						
83							

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ALLOCATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
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CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
84	Total Plant Demand		$ 19,852,036	$ 12,930,894	$ 4,491,581	$ 2,211,392	$ 218,169
85	**Total Plant Demand Factor (TPLTDEM)**	**TPLTDEM**	**1.00000**	**0.65136**	**0.22625**	**0.11139**	**0.01099**
86							
87	Operating Expense Demand		$ 1,515,696	$ 981,037	$ 346,975	$ 157,183	$ 30,501
88	**Operating Expense Demand Factor (OPEXPDEM)**	**OPEXPDEM**	**1.00000**	**0.64725**	**0.22892**	**0.10370**	**0.02012**
89							
90	Acct. 887-893 Demand		$ 647,562	$ 385,502	$ 170,068	$ 83,731	$ 8,261
91	**Acct. 887-893 Demand Factor (887-893DEM)**	**887-893DEM**	**1.00000**	**0.59531**	**0.26263**	**0.12930**	**0.01276**
92							
93	Rate Base Demand		$ 11,643,939	$ 7,537,331	$ 2,665,046	$ 2,072,624	$ (631,062)
94	**Rate Base Demand Factor (RBDEM)**	**RBDEM**	**1.00000**	**0.64732**	**0.22888**	**0.17800**	**-0.05420**
95							
96	**Commodity Cost Allocation Factors**						
97							
98	Annual Distribution Volumes (Ccf)		$ 24,911,022	14,178,009	8,486,064	686,830	1,560,118
99	**Distribution Commodity Factor (COM)**	**COM**	**1.00000**	**0.56915**	**0.34066**	**0.02757**	**0.06263**

CLASS REVENUE ALLOCATION

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

CLASS REVENUE ALLOCATION

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)
1	Current Revenue-to-Cost Ratio (1)	0.9377	0.8170	2.1119	0.8289	4.1391
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	$ 1,191,979	$ 3,150,411	$ (1,591,358)	$ 59,954	$ (427,028)
6	% Increase - Non-Gas Revenue (2)	6.64%	22.39%	-52.65%	20.64%	-75.84%
7	% Increase - Total Revenue (3)	4.17%	14.92%	-27.27%	20.64%	-31.90%
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)					
9	Revenue-to-Cost Ratio	1.0000	0.9090	1.8896	0.8631	3.5112
10	Rate Design Revenue Increase	$ 1,191,979	$ 1,583,665	$ (318,272)	$ 11,991	$ (85,406)
11	% Increase - Non-Gas Revenue (2)	6.64%	11.26%	-10.53%	4.13%	-15.17%
12	% Increase - Total Revenue (3)	4.17%	7.50%	-5.45%	4.13%	-6.38%
13	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)					
14	Revenue-to-Cost Ratio	1.0000	0.8863	2.1119	0.8289	4.1391
15	Rate Design Revenue Increase	$ 1,191,979	$ 1,191,979	$ -	$ -	$ -
16	% Increase - Non-Gas Revenue (2)	6.64%	8.47%	0.00%	0.00%	0.00%
17	% Increase - Total Revenue (3)	4.17%	5.64%	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.

Exhibit CDD-7
Page 1 of 1

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF CRYSTAL DRUMM

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

1. "My name is Crystal Drumm. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as a Rates Specialist 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 this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Crystal Drumm

Crystal Drumm

SUBSCRIBED AND SWORN TO BEFORE ME by the said Crystal Drumm on this 9th day of December, 2019.

JOANNE C. DAVIS
NOTARY
05009895
EXP. 10/25/21
PUBLIC
STATE OF OKLAHOMA

Joanne C Davis

Notary Public in and for the State of Oklahoma

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

PAUL H. RAAB

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

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LIST OF EXHIBITS

DIRECT TESTIMONY OF PAUL H. RAAB

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 ("TGS" or "the Company"), a Division of ONE Gas, Inc. ("ONE Gas").

I. INTRODUCTION AND QUALIFICATIONS

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 my entire career, 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 THIS 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 Central-Gulf Service Area ("CGSA") based on the CGSA class cost of service ("CCOS") study results sponsored by TGS witness Crystal D. Drumm.

Q. DID YOU ALSO DEVELOP SEPARATE RATES FOR THE CENTRAL TEXAS SERVICE AREA ("CTSA") AND THE GULF COAST SERVICE AREA ("GCSA")?

A. Yes. I developed rates based on the separate CTSA and GCSA revenue requirements in order to set rates in the event consolidation of the two service areas is not approved.[1] Exhibit PHR-7 provides the proposed rates for the CTSA, and Exhibit PHR-12 provides the proposed rates for the GCSA based on each area's separate revenue requirement. Each of these exhibits is presented in the same format as the proposed CGSA rates proposed in Exhibit PHR-2. Thus, my explanation of content of Exhibit PHR-2 applies to Exhibit PHR-7 and to Exhibit PHR-12.

II. RATE DESIGN

Q. PLEASE DESCRIBE THE CURRENT RESIDENTIAL RATES IN THE CTSA AND THE GCSA.

A. Current CTSA and GCSA rate structures consist of a fixed customer charge and usage charges for each customer class, including the residential class. The residential customer charge is $18.81/customer/month in the environs and incorporated CTSA, $12.42 in the incorporated GCSA, $14.17 in the GCSA environs and $12.10 in the City of Beaumont.

Residential usage is priced at a single per Ccf rate of $0.12061 in the CTSA environs and incorporated areas, $0.45616 in the GCSA incorporated areas and the City of Beaumont and $0.40680 in the GCSA environs.

[1] Rate design for customers in the City of Beaumont is included in GCSA.

Q. PLEASE DESCRIBE THE CURRENT COMMERCIAL RATES.

A. For commercial sales customers, current customer charges are $53.33/customer/month in the CTSA, $51.11 in the GCSA incorporated areas, $59.92 in the GCSA environs and $49.49 in the City of Beaumont. Commercial usage is priced at a single per Ccf rate of $0.11614 in the CTSA and under a declining block structure in the GCSA incorporated areas and environs and the City of Beaumont. Monthly consumption less than or equal to 250 Ccf is priced at $0.22140 in the GCSA incorporated areas and the City of Beaumont and $0.20185 in the GCSA environs and monthly consumption greater than 250 Ccf is priced at $0.19380 in the GCSA incorporated areas and the City of Beaumont and $0.17425 in the GCSA environs.

The usage of commercial transportation customers is priced at the same volumetric rate as sales customers in both service areas. Customer charges for commercial transportation customers of $265.33/customer/month in the CTSA, $297.11 in the GCSA incorporated areas and $305.92 in the GCSA environs reflect the higher metering costs associated with providing service to these customers.

Q. PLEASE DESCRIBE THE CURRENT INDUSTRIAL RATES.

A. For industrial sales customers, current customer charges are $320.96/customer/month in the CTSA, $153.41 in the GCSA incorporated areas and $242.79 in the GCSA environs. Industrial usage is priced at a single per Ccf rate of $0.10273 in the CTSA and under a declining block structure in the GCSA incorporated areas and environs. Monthly consumption less than or equal to 250 Ccf is priced at $0.40060 in the GCSA incorporated areas and $0.37808 in the

GCSA environs and monthly consumption greater than 250 Ccf is priced at $0.37480 in the GCSA incorporated areas and $0.35228 in the GCSA environs.

The usage of industrial transportation customers is priced at the same volumetric rate as sales customers in both service areas. Customer charges for industrial transportation customers of $520.96/customer/month in the CTSA, $249.73 in the GCSA incorporated areas and $432.79 in the GCSA environs also reflect the higher metering costs associated with providing service to these customers.

Q. PLEASE DESCRIBE THE CURRENT PUBLIC AUTHORITY RATES.

A. For public authority sales customers, current customer charges are $81.70/customer/month in the CTSA, $106.10 in the GCSA incorporated areas and $117.78 in the GCSA environs. Like the commercial and industrial rates described above, public authority usage is priced at a single per Ccf rate of $0.11541 in the CTSA and under a declining block structure in the GCSA incorporated areas and environs. Monthly consumption less than or equal to 250 Ccf is priced at $0.15672 in the GCSA incorporated areas and $0.13587 in the GCSA environs and monthly consumption greater than 250 Ccf is priced at $0.13092 in the GCSA incorporated areas and $0.11007 in the GCSA environs.

The usage of public authority transportation customers is priced at the same volumetric rate as sales customers in both service areas. Customer charges for public authority transportation customers of $104.70/customer/month in the CTSA, $302.36 in the GCSA incorporated areas and $307.78 in the GCSA environs also reflect the higher metering costs associated with providing service to these customers.

Q. PLEASE DESCRIBE THE CURRENT PUBLIC SCHOOLS SPACE HEATING RATES.

A. In both the CTSA incorporated areas and environs, public schools space heating sales customers are served under a two-part rate consisting of a customer charge of $134.70/customer/month and a single usage charge of $.10012/Ccf. The usage of public schools space heating transportation customers is priced at the same volumetric rate as sales customers. Customer charges for public schools space heating transportation customers are $234.70/customer/month. The Company does not currently offer a separate rate for public schools space heating customers in the GCSA.

Q. PLEASE DESCRIBE THE CURRENT COMPRESSED NATURAL GAS RATES.

A. In both the CTSA incorporated areas and environs, compressed natural gas sales customer charges are $192.63/customer/month and usage is priced at $0.06684 per Ccf for all usage. For compressed natural gas transportation customers, customer charges are $217.63/customer/month and usage is priced at the same rate as compressed natural gas sales customers, $0.06684 per Ccf for all usage. The Company does not currently offer a separate rate for compressed natural gas customers in the GCSA.

Q. PLEASE DESCRIBE THE CURRENT ELECTRICAL COGENERATION RATES.

A. In both the CTSA incorporated areas and environs, electrical cogeneration sales and transportation customers are served under the same rate: a customer charge of $104.70/customer/month and a declining block rate structure for usage. The

Company does not currently offer a separate rate for electrical cogeneration customers in the GCSA. The current blocking structure for usage is as follows:

Electrical Cogeneration Usage Rates

Volumes	Rates
First 5,000 Ccf	$0.07720
Next 35,000 Ccf	$0.06850
Next 60,000 Ccf	$0.05524
All Over 100,000 Ccf	$0.04016

Q. HOW DID YOU DESIGN THE PROPOSED CGSA RATE RECOMMENDATIONS?

A. I began with class revenue recommendations developed by Ms. Drumm. As described more fully by Ms. Drumm, those recommendations are the result of applying class Revenue Allocation Three, under which only those classes that are indicated to be contributing revenues less than their full cost of service are assigned a portion of the revenue deficiency and the rates of those classes that are indicated to be contributing revenues in excess of their full cost of service are not reduced. Furthermore, to ensure rate continuity, I relied on the current incorporated CTSA 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' 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 and winter bill impacts for each customer class. Both average monthly and average winter bills are examined to ensure that disproportionately large impacts do not occur in the winter when customers have the highest bills and could have trouble in paying them. Furthermore, because the Company is proposing a slightly different rate structure for residential customers than 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 for the class, there will be a wide disparity in customer bill impacts, some of which will be large.

Finally, when designing rates, it is important that customers can easily determine which rate offering is most appropriate for their usage level. By keeping the usage charge the same for sales and corresponding transportation classes, this is accomplished.

Q. HAVE YOU IDENTIFIED ANY CHALLENGES IN DESIGNING RATES FOR THE PROPOSED CGSA?

A. Yes. First, current rates in the GCSA and CTSA 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 two service areas.

Second, current monthly rate levels differ significantly between the CTSA and GCSA and between incorporated areas and the environs of the GCSA. 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, in both the CTSA and GCSA, current residential customer charges are below the fixed cost per bill indicated by the CGSA CCOS study. 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 CGSA?

A. Even if one were to apply the higher customer charges associated with the CTSA ($18.81/customer/month) to all customers in the consolidated CGSA, the resulting CGSA usage rates would collect 29% of total residential revenue, while the CGSA CCOS study shows that residential variable costs are less than 0.5% of the cost to serve the class. As a result, current residential customer charges significantly under-recover residential fixed costs. These residential rates lead to moderate- and high-use customers paying a disproportionately large share of the cost to serve the class.

The Company's proposal to address this inequity is so-called "usage level" or "A/B" rate designs ("A/B Rates") for the residential class. A/B Rates allow the Company to improve its fixed cost recovery while avoiding the rate shock problem associated with simply raising customer charges to levels indicated by the COSS. Such a rate design includes multiple two-part rates for the same class of customers.

One set of rates (the "A" Option) is more advantageous for lower usage customers because it has a low customer charge and higher usage rates. The other set of rates (the "B" Option) is more advantageous for higher usage customers because it has lower usage rates but a higher customer charge. While there is no theoretical restriction on the number of rate options that could be offered, from the standpoints of customer understandability and ease of administration, two is a reasonable compromise that gives customers with different usage patterns a distinct choice in how they are billed for service.

The annual consumption level at which customers are economically indifferent to one rate option versus the other is the "breakpoint." While there is a clear option advantage for customers depending on their normal usage levels, they can choose the option under which they would rather be served, so long as they remain with that option for one year.

Q. PLEASE DESCRIBE THE USAGE LEVEL OPTIONS THAT YOU PROPOSE.

A. The proposed usage level options can be summarized as follows:

Residential Option A customers in the proposed CGSA whose weather normalized consumption is less than or equal to 360 Ccf per year:

Customer charge:	$14.00/customer/month
Volumetric Charge:	$0.55702/Ccf

Residential Option B customers in the proposed CGSA whose weather normalized consumption is greater than 360 Ccf per year:

Customer charge:	$27.58/customer/month
Volumetric Charge:	$0.10435/Ccf

Q. PLEASE DESCRIBE HOW YOU DEVELOPED THESE OPTIONS.

A. As stated above, I began with the Company's CCOS study 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 $27.58 most accurately captures the customer-related and demand-related costs by class identified in the Company's CCOS study as described by Ms. Drumm.

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 bills experienced in the residential class, resulted in significant bill increases relative to the Company's current rate structures in the CTSA and GCSA for lower usage customers.[2] 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 $14.00/customer/month, a level approximating the lowest customer charge that residential customers are currently charged in the GCSA environs, GCSA incorporated or CTSA service areas. I also propose that, since higher usage level customers will not face rate shock issues as a result 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. The only question then left to answer was how to distinguish between a lower usage Option A customer and a higher usage Option B customer.

Q. HOW DID YOU MAKE THAT DETERMINATION?

A. In effect, I let the competing rate options applicable to a customer class make that decision for me. I did this by determining that level of annual consumption at which a customer's bill would be equal under either option. Since consumption below

[2] As mentioned previously, City of Beaumont customers are included with the GCSA.

this annual consumption level results in lower bills under the Option A rate, this is the preferred option for the lower usage customers. Conversely, since consumption above this annual consumption level results in lower bills under the Option B rate, this is the preferred option for the higher usage customers.

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 options, 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 decided to recover the intraclass subsidy through an equal, additional charge applied to the usage charges of both rate options so that both Option A and Option B 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 the higher usage and lower usage rate options implement a simple two-part structure (customer charges and volumetric charges), they can be implemented very simply and in a way that is transparent to customers. In fact, a significant advantage of these rate options is that if a customer finds himself or herself on a disadvantageous rate option (the lower usage one versus the higher usage one or vice-versa), he or she can change the rate to better reflect their usage patterns as provided for in the residential gas sales rate schedule. The only restriction would be that customers must remain on one option or the other for a full year. Otherwise, customers could simply choose the lower usage option in the summer and the higher usage option in the winter, which would result in significant revenue erosion to the Company.

But, importantly, the proposed rate design allows the Company to provide customers some choice in their rates.

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 which option they choose, so the Company does not expect significant migration of customers from one option to the other. This can be seen by comparing the annual bills for two customers near the breakpoint between options. Consider a residential customer who uses exactly 360 Ccfs per year. Under the lower usage rate option, the customer's annual bill is $368.53, the same amount as under the higher usage rate option. If the customer reduces usage by 90%, to 324 Ccfs per year, there is only a small difference in the annual bill between the customer's most economical rate schedule (Option A) and the alternative ($348.47 versus $364.77, or $1.36 per month). A similar result is obtained 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 advantage of the rate option that best fits their needs. As a result, most customers will not be much affected, and the Company's revenues will not change radically as a result of rate shifts.

At the same time, if a customer were willing to agree to stay on one rate or the other for one year, the choice of which option to be billed under can be his or hers.

Q. HOW WILL THE COMPANY DETERMINE WHICH RATE TO APPLY TO CUSTOMERS INITIALLY?

A. The Company will initially apply the rate option for the customer based on the rate that appears to be the most economical based on their historical usage and then allow customers to switch if they believe the other rate will better suit them due to changed circumstances or personal preferences, subject to the restriction I mentioned before that they would only be allowed to switch once per year.

Q. DOES ONE GAS HAVE EXPERIENCE WITH THIS TYPE OF RATE STRUCTURE?

A. Yes, Oklahoma Natural Gas, another division of ONE Gas, has been serving residential and small and large commercial customers under this type of rate design for 15 years.

Q. WHY IS THE COMPANY MAKING THIS RATE DESIGN PROPOSAL FOR RESIDENTIAL CUSTOMERS AND NOT FOR OTHER CUSTOMER CLASSES?

A. For two reasons. First, as demonstrated below by an application of Bonbright's attributes of a sound rate structure, this is a more fundamentally sound rate structure for residential customers than the simple two-part rate applied to all customers that it is intended to replace. Second, as will also be demonstrated below, 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 GCSA incorporated service area. This proposal mitigates those impacts, particularly for lower usage customers. Furthermore, because the new rate designs that include usage level options can be shown to better reflect the Company's cost structure, economic efficiency gains should accrue.

Q. PLEASE EXPLAIN THE RECOMMENDED RATE DESIGN FOR THE NON-RESIDENTIAL PROPOSED CGSA TRANSPORT AND SALES CLASSES.

A. Except for cogeneration, I recommend a two-part, single-block rate structure that is currently in place in the CTSA incorporated areas. 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 CGSA CCOS study 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. Current rates are shown in columns (b) through (d) and recommended rates are shown in columns (e) and (f).

Q. ARE YOUR RECOMMENDED NON-RESIDENTIAL RATES FOR THE CTSA AND GCSA DEVELOPED IN THE SAME MANNER IF THE TWO SERVICE AREAS ARE NOT CONSOLIDATED IN THIS SOI?

A. Yes, they are. Current and recommended non-residential rates are shown in Exhibit PHR-7 for the CTSA and in Exhibit PHR-12 for the GCSA. These rates are recommended if the two service areas are not combined in this SOI.

Q. IN YOUR OPINION, IS YOUR RATE DESIGN JUST AND REASONABLE?

A. Yes.

III. EVALUATION OF THE PROPOSED RATE DESIGNS

Q. HOW WILL YOU EVALUATE THE RESIDENTIAL RATE DESIGNS INTRODUCED IN THE PREVIOUS SECTION?

A. I will evaluate the rate design proposals by applying a set of objective rate design criteria to the current, two-part tariffs and the new, usage level option rate designs in turn. The rate design criteria I use for this purpose are those developed by Bonbright.[3]

Q. WHAT ARE BONBRIGHT'S ATTRIBUTES OF A SOUND RATE STRUCTURE?

A. In his seminal work, Principles of Public Utility Rates, Professor Bonbright introduces ten attributes of a sound rate structure. Bonbright characterizes these attributes as "desirable characteristics of utility performance that regulators should seek to compel through edict," and groups the attributes into those related to revenues, those related to cost, and those related to practicality. The three revenue-related attributes are:[4]

1. Effectiveness in yielding total revenue requirements under the fair- return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.
2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.
3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to the ratepayers and with a sense of historical continuity.

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[3] Bonbright, James C., Danielson, Albert L., & Kamerschen, David R. , *Principles of Public Utility Rates.* Arlington, VA: Public Utilities Reports, Inc. (1988).
[4] *Id.* at 383.

Five are related to cost, and these are:[5]

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. Reflection of all the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).

6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

7. Avoidance of undue discrimination in rate relationships to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).

8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

The final two attributes are related to practicality. These attributes are:[6]

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

Q. DOES THE COMPANY'S CURRENT RATE STRUCTURE POSSESS THE FIRST TWO OF BONBRIGHT'S ATTRIBUTES?

A. No, as explained in the previous section of my testimony, it does not.

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[5] *Id.* at 383-84.
[6] *Id.* at 384.

Q. DOES THE CURRENT RATE STRUCTURE COME UP SHORT FROM THE PERSPECTIVE OF ANY OF THE OTHER ATTRIBUTES LISTED ABOVE?

A. Yes. One of the critical features of a mismatch between cost incurrence and cost recovery of the type exhibited by the Company's rate structure is that it builds subsidies into the prices faced by consumers for the delivery of natural gas. Specifically, by collecting costs that have been identified as fixed in volumetric rates, it is a mathematical certainty that larger users of the natural gas distribution system will pay more than the identified cost to serve them and will subsidize lower usage customers. At the same time, all consumers will pay more than the identified cost to serve them during the heating season when usage is highest, resulting in the potential for considerable bill impacts during winter months. Thus, TGS's current rate structure can also be said to violate the static efficiency standard (attribute 4), the fairness standard (attribute 6) and the avoidance of undue discrimination standard (attribute 7).

Q. IN CONTRAST, HOW DOES THE A/B RATE DESIGN THAT YOU PROPOSE PERFORM WHEN EVALUATED BY BONBRIGHT'S CRITERIA?

A. The proposed usage level rate designs are superior to the Company's existing rate designs when measured against each of the three revenue-related criteria established by Bonbright.

Q. PLEASE EXPLAIN.

A. The first evaluation I have performed measures the effectiveness of the rate structure in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety. Consider first the rate structure's ability to yield total revenue requirements under the fair-return standard. The Company's proposed usage level rate designs will clearly better satisfy this objective than the Company's current rate designs for three reasons. First, as I discussed earlier, the Company's CCOS study demonstrates that almost 100% of the costs of serving customers are fixed, but 35% of those costs are collected through volumetric charges. Since natural gas usage has historically declined and is forecast to continue to decline, existing volumetric-based rate designs will increasingly under-collect Commission-authorized levels of revenues and put financial pressure on the Company.

Q. IS THERE MORE TO THE FIRST ATTRIBUTE THAN THE SIMPLE ABILITY TO RECOVER COST?

A. Yes. The two additional features of this attribute are: the ability of the rate to collect the desired level of revenues without any socially undesirable expansion of the rate base and the ability of the rate to collect the desired level of revenues without providing a socially undesirable level of product quality and safety. In either case, one is concerned with sending a price signal that is too low so that either wasteful consumption occurs, or insufficient revenues are generated to allow the Company to maintain appropriate quality of service levels.

Q. HOW CAN YOU DETERMINE WHETHER A PARTICULAR RATE DESIGN WILL LEAD TO SOCIALLY UNDESIRABLE LEVELS OF CONSUMPTION?

A. There are two factors that one can consider when making such a determination: The Company's cost of providing service; and the incentives that are provided to the Company to promote consumption or conservation.

Q. WHAT DOES THE COMPANY'S COST OF SERVICE TELL US ABOUT WHETHER THE USAGE LEVEL RATE DESIGNS WILL PROMOTE SOCIALLY UNDESIRABLE LEVELS OF CONSUMPTION?

A. Given the level of revenues collected from fixed and variable components of each rate and the corresponding fixed and variable costs as identified by the Company's CCOS study filed in this case, it is clear that intraclass subsidies are still an element of the proposed usage level rate designs. These subsidies will tend to promote socially undesirable levels of consumption. However, the proposed usage level rate designs reduce the subsidies to the extent practicable, given the desire to minimize rate shock among the Company's residential customers, and will therefore promote a more economically efficient level of consumption than the Company's current two-part rates.

Q. HOW CAN YOU DETERMINE WHETHER A PARTICULAR RATE DESIGN WILL LEAD TO SOCIALLY UNDESIRABLE LEVELS OF PRODUCT QUALITY AND SAFETY?

A. For purposes of responding to this question, I assume that the level of revenues associated with the Company's authorized return is the level of revenues that corresponds to a socially desirable level of product quality and safety. In other words, when the Company earns its authorized return, as determined by this Commission in setting the Company's rates, it is earning revenues that enable it to maintain a socially desirable level of product quality and safety.

Q. WHAT THEN DOES AN ANALYSIS OF THE COMPANY'S EMBEDDED COSTS TELL US ABOUT THE COMPANY'S CURRENT RATE DESIGNS?

A. This analysis demonstrates that there are subsidies in the Company's current rate designs such that low users are consuming more than economically efficient levels and large users are consuming less than the economically efficient level.

Q. DO THE COMPANY'S RATE STRUCTURES ENCOURAGE LOW USAGE CUSTOMERS TO USE MORE AND HIGHER USERS TO USE LESS?

A. Yes. Consider, for example, a low use customer who uses natural gas solely for cooking. The Company maintains the same infrastructure for that customer as it does for the customer who heats his home and water with natural gas, but the cooking customer pays for only a fraction of that infrastructure. Thus, the cooking-only customer receives a significant subsidy from all other customers on the system.

Under current rate structures, the only way for the low use customer to compensate the Company for the infrastructure it has installed to serve him is to use more natural gas. This can be accomplished in two ways. First, the customer can use his existing appliances more intensively, but it is unlikely that the customer will cook more meals or dry more clothes simply because the price is low. Thus, the only realistic action that a low use customer can take is to install more natural gas appliances.

But now consider what happens under the Company's existing rate structures after this change: the one-time low usage customer, who would now, likely, be a space-heating customer, is now a higher usage customer and now provides the subsidy. Thus, the impact of the Company's current rate structures is to (uneconomically) encourage low-use customers to come on and stay on the system and to discourage high usage/space heating customers from coming on the system, forcing them instead to choose alternative, and potentially less economically efficient, energy sources.

Q. SINCE THE PROPOSED USAGE LEVEL OPTIONS RELY MORE HEAVILY ON CUSTOMER-RELATED CHARGES TO COLLECT COMMISSION-AUTHORIZED REVENUES, WILL THIS DISCOURAGE THE COMPANY FROM PROMOTING ECONOMICALLY EFFICIENT CONSERVATION?

A. No. A rate structure that is dominated by customer-related charges will provide stronger incentives for the utility to promote conservation than will a rate structure that relies heavily on volumetric charges, as explained more fully below. Furthermore, because the charges better match the costs of providing service, consumers receive a more accurate price signal of the consequences of their consumption decisions to use more or to use less.

Q. WHY WILL A RATE STRUCTURE WITH A HIGHER CUSTOMER-RELATED CHARGE PROVIDE STRONGER INCENTIVES FOR THE UTILITY TO PROMOTE CONSERVATION THAN A RATE STRUCTURE WITH HIGHER VOLUMETRIC CHARGES?

A. Under a volumetric-based rate, utilities rely on static or increasing consumption to maintain their financial health. Rate structures such as the one that I propose here provide a stronger incentive for utilities to promote conservation because they "decouple" the utility's volumetric sales from its profitability. Thus, the utility is not penalized in the form of decreased earnings for encouraging the efficient use of natural gas. This "conservation penalty" associated with traditional rate structures has been recognized by the National Association of Regulatory Utility Commissioners, State Regulatory Authorities throughout the country, the American Gas Association and the Natural Resources Defense Council.

Q. WHY IS IT IMPORTANT THAT A RATE DESIGN PROVIDE CONSUMERS WITH A MORE ACCURATE PRICE SIGNAL OF THE CONSEQUENCES OF THEIR CONSUMPTION DECISIONS TO USE MORE OR TO USE LESS?

A. It is the job of a rate structure to provide the correct price signal. Consumers can then use the cost information contained in the rate and make consumption trade-offs between the cost of energy and the costs of durable goods to make economically efficient consumption decisions, which may even result in more consumption of natural gas. In my opinion, signaling to consumers that the consumption of more distribution service has significant cost consequences is misleading and unwise when all cost bases for all economic time horizons indicate this not to be the case.

Q. WHICH OF THE RATE STRUCTURES PROVIDES MORE STABLE AND PREDICTABLE REVENUES FOR TEXAS GAS SERVICE?

A. As discussed above, revenue stability and predictability will be enhanced under the proposed usage level rate designs because they better reflect cost causation so that as volumes change as a result of conservation, efficiency gains or warm weather, the revenues and costs will be more synchronized.

Q. WHICH OF THE RATE STRUCTURES PROVIDES MORE STABLE AND PREDICTABLE RATES FOR TEXAS GAS'S CUSTOMERS?

A. Rate stability and predictability are often referred to as rate continuity. In the context of this rate proposal, there are two dimensions to rate continuity. The first is the degree to which rates remain stable and predictable as they are being implemented. Clearly, because the introduction of any new rate design leads to different rates, there is an element of rate discontinuity, simply because rates themselves have changed. However, as described in the previous section of my testimony, the usage level rate designs have been developed to mitigate significant bill increases, so there are also benefits to the proposed rate structure from a rate continuity standpoint.

The second dimension to rate continuity is the degree to which rates remain stable and predictable after they are implemented. In this case, the new rate designs are vastly superior to the existing rate designs because they will not change due to the volume declines documented above.

In addition, under the current rate design, prices are the highest in the winter, when natural gas prices are also likely to be higher. Thus, after implementation, not only will the proposed usage level rate designs be more stable and more predictable for customers, but they could also produce additional benefits in the form of lower arrearages and less disconnects.

Q. TURNING NOW TO THE COST-BASED ATTRIBUTES, WHAT DOES THE STATIC EFFICIENCY ATTRIBUTE REQUIRE?

A. The static efficiency attribute requires that customers receive a cost-based price signal. This in turn requires that the price includes all costs, but no “extra” costs such as are imposed when a subsidy is extracted, and no “discounts” such as are provided when a subsidy is received. In order to satisfy this rate design attribute, it is necessary to eliminate three kinds of subsidies: interclass, intra-class and seasonal.

Q. WHY IS IT IMPORTANT THAT CUSTOMERS RECEIVE A PRICE SIGNAL FREE FROM SUBSIDIES?

A. Those groups that are receiving subsidies are receiving service at less than cost and will therefore engage in wasteful consumption. Conversely, those groups that are providing the subsidies (i.e., paying rates that result in a return to the Company greater than the system average return) will consume less than their economically efficient level of consumption. This has efficiency consequences for all related economic sectors such as electricity and durable goods. In this context, the “groups” we are concerned with are customer classes (to measure interclass subsidies), customers who consume different amounts of energy within the same class (to measure intra-class subsidies) and customers who have different seasonal load patterns within the same class (to measure seasonal subsidies).

Q. IS YOUR PROPOSED A/B RATE DESIGN BETTER AT ELIMINATING INTERCLASS SUBSIDIES THAN THE COMPANY'S CURRENT TWO-PART RATE?

A. No, because this issue is addressed by the allocation of the revenue deficiency, for which the Company has chosen Revenue Allocation Three, as described above.

Q. IS YOUR PROPOSED A/B RATE DESIGN BETTER AT ELIMINATING INTRA-CLASS SUBSIDIES THAN THE COMPANY'S CURRENT TWO-PART RATE?

A. Yes, because they better match the identified cost of service, usage level rate designs will better eliminate the intra-class subsidies inherent in the current, volume-based rate structure that the Company currently has in place.

Q. WHICH OF THE RATE DESIGNS FARES BETTER FROM THE STANDPOINT OF ELIMINATING SEASONAL SUBSIDIES?

A. Because traditional rate designs collect fixed costs in volumetric rates, it is a mathematical certainty that residential consumers are paying more for the delivery of natural gas in the winter than their cost of service. The opposite situation prevails in the summer when customers receive a subsidy, on average, of about the same amount. This analysis demonstrates another flaw in the current rate designs that is corrected by the usage level rate option. Consumers are paying unnecessarily high winter bills for the distribution of natural gas at just the time when they need the most relief from higher bills. One of the benefits for Option B customers is that the seasonal volatility is largely eliminated. On the other hand, Option A customers are not large users and are less likely to experience the seasonal volatility in the first place, so both types of customers benefit.

Q. BESIDES ELIMINATING SUBSIDIES, ARE THERE OTHER RATE DESIGN FEATURES THAT ARE REQUIRED BY THE STATIC EFFICIENCY ATTRIBUTE?

A. Yes. The rate design must discourage wasteful use and encourage all justified types and amounts of use. This attribute requires first that the rate design provide an economically efficient price signal. As demonstrated above, the proposed usage level rate designs better match the costs of providing service than the Company's current rate designs and are therefore better able to provide such a price signal. This attribute also requires that the Company be provided with the proper financial incentives to the extent market interventions are desired to promote conservation of natural gas. Again, the discussion above indicates that, to the extent such interventions are desired, the proposed usage level rate designs will provide the Company with better incentives to make those interventions without financial penalty.

Q. YOU INDICATE ABOVE THAT THE STATIC EFFICIENCY ATTRIBUTE ALSO REQUIRES THAT THE RATE PROVIDE THE PROPER PRICE SIGNAL FOR CONSUMERS TO CHOOSE BETWEEN HIGHER QUALITY AND LOWER QUALITY SERVICE. WHICH OF THE COMPETING RATE DESIGNS BETTER SATISFIES THIS FEATURE OF THE ATTRIBUTE?

A. Since the residential class either does not have lower quality services available to it or does not have a lower cost service available at a commensurately lower price, neither of the competing rate designs will influence the economic decision to transport or to take interruptible service.

Q. WHAT ARE INTERNALITIES AND EXTERNALITIES?

A. They are effects on one party that emanate from the action of another party. When the effect is positive, an internality has been said to have been created; when negative, an externality. In the context of energy usage, externalities associated with pollution are often cited as being particularly important.

Q. WHY ARE THEY IMPORTANT IN THE RATE SETTING PROCESS?

A. They are important because externalities have a cost and they impose that cost on the non-cost-causer. Thus, the cost of the consumption decision to the consumer is understated by the value of the externality. When costs are understated (or over-stated) economically efficient decision-making is thwarted and too much (or too little) consumption occurs.

Q. WHICH OF THE COMPETING RATE DESIGNS BETTER CAPTURES INTERNALITIES AND EXTERNALITIES?

A. Because both rate designs are designed to recover the same level of revenues, both reflect an equal number of internalities and externalities. However, the ability of the proposed usage level rate design to provide better incentives to the utility to encourage energy efficient investments (thereby implicitly recognizing whatever pollution externalities might exist) makes it a better rate design.

Q. WHAT DOES THE FAIRNESS ATTRIBUTE REQUIRE?

A. The fairness attribute requires that rates be equitable. Bonbright addresses three dimensions of equity: horizontal, vertical, and anonymous.

Q. WHAT DOES HORIZONTAL EQUITY REQUIRE?

A. Horizontal equity requires that equals be treated equally. Specifically, it requires that if there are two consumers who take the same quality of service at the same level, they pay the same.

Q. WHAT IS VERTICAL EQUITY?

A. Vertical equity is a measure of fairness that requires that unequals be treated differently. Consistent with the discussion from above, it requires that if two consumers take service that costs the utility different amounts to provide, then they should pay something different for that service.

Q. WHAT IS ANONYMOUS EQUITY?

A. Anonymous equity is another concept of fairness that requires that no ratepayer's demands be diverted away uneconomically from the incumbent supplier. This is particularly relevant for natural gas companies such as TGS, since natural gas has readily available substitutes for each of its end-uses.

Q. HOW DO THE CANDIDATE RATE DESIGN OPTIONS PERFORM AGAINST THESE EQUITY CRITERIA?

A. To the extent that the proposed usage level rate design is better at eliminating subsidies of all types and to the extent that this rate design more accurately reflects the costs of service, it is clear that the proposed usage level rate design will be fairer than TGS's current rate designs. One of the benefits of customer choice is that the customer gets to choose the rate that they believe is most fair.

Q. WHAT IS REQUIRED BY THE AVOIDANCE OF UNDUE DISCRIMINATION ATTRIBUTE?

A. The avoidance of undue discrimination attribute requires that each customer class pay its fair share of costs and no more. Specifically, it requires that there be no interclass, intra-class and seasonal subsidies. As I have shown above, each of these is reduced under the Company's usage level rate design proposals.

Q. WHAT IS DYNAMIC EFFICIENCY?

A. In the context of Bonbright's criteria, dynamic efficiency refers to the rate structure's ability to provide the correct long run price signal to foster the economically correct consumption decisions and then to continue to provide the correct long run price signal after those consumption decisions have manifested themselves in the form of new load levels.

Q. HOW CAN ONE BE CERTAIN THAT A RATE STRUCTURE PROMOTES DYNAMIC EFFICIENCY?

A. Economic theory argues that a rate structure that is based on the long run marginal cost of providing service will promote dynamic efficiency.

Q. WHAT ARE THE CONSEQUENCES OF A RATE STRUCTURE THAT DOES NOT PROMOTE DYNAMIC EFFICIENCY?

A. It is easiest to explain this concept by example. Consider making energy efficiency investments based on the Company's current rate design. This rate design signals consumers that each Ccf they conserve is worth between $0.12061 and $0.45616, even though the cost of service study indicates that these conserved Ccfs are worth a fraction of this amount. Assume now that a consumer makes an energy efficiency investment based on these numbers. Between rate cases, this investment pays off at the indicated volumetric rate. However, when rates are reset at the next rate case, the Company has not saved the equivalent of the indicated retail rate amount, but something closer to $0.003/Ccf. Thus, rates are set to collect these lost revenues, the volumetric rate increases, and the return on the efficiency investment declines. Setting rates closer to cost of service, as usage level rate designs do, will ensure that this does not happen.

Q. PLEASE DISCUSS THE PRACTICALITY ATTRIBUTES THAT CAN BE USED TO EVALUATE A PROPOSED RATE DESIGN.

A. The practicality attributes are simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

Q. HOW DO THE COMPETING RATE DESIGNS COMPARE FROM THE STANDPOINT OF THESE PRACTICALITY ATTRIBUTES?

A. For the most part, these criteria favor neither rate design. For example, I would consider the attributes of convenience of payment, economy in collection, understandability, public acceptability and feasibility of application to be equally satisfied by both rate designs.

With respect to the simplicity criterion, one could argue that a rate design that is more heavily weighted toward fixed charges is simpler than the Company's current rate design. However, gradualism considerations dictate that the final rate design incorporate both fixed and variable cost components.

Finally, I would argue that the proposed usage level rate designs incorporate far more certainty than the Company's current rate design due to the volatility of usage with respect to weather. Because of this, I believe that these practicality attributes favor the proposed usage level rate designs over the Company's current rate designs. However, neither dominates and these are secondary criteria in any case.

Q. DO YOU HAVE CONCERNS THAT CUSTOMERS WILL MISINTERPRET THE RATE DESIGNS?

A. No. Both proposals are rate designs that customers are well-accustomed to seeing and responding to. Therefore, the selection of the best rate design for TGS's customers in Texas cannot be decided based on how well each one satisfies this criterion. However, in all fairness, this criterion is, at best, of secondary importance and should not be used to select between competing rate designs unless one of the alternatives is simply not understandable.

Q. PLEASE SUMMARIZE YOUR EVALUATION OF THE COMPANY'S CURRENT RATE DESIGNS AND THE PROPOSED USAGE LEVEL RATE OPTIONS IN THIS CASE BY USING BONBRIGHT'S SOUND RATE DESIGN CRITERIA.

A. Based on the above discussion, the proposed usage level rate designs are superior to the Company's current rate designs. The following attributes unequivocally favor the proposed usage level rate designs:

1. Effectiveness in yielding total revenue requirements. The proposed usage level rate designs will better satisfy this objective because they will better match fixed costs with fixed charges, they will reduce intra-class subsidies relative to current rate designs, they better match the costs of providing service and they provide the Company with better incentives to pursue conservation.

2. Revenue stability and predictability. The proposed usage level rate designs better reflect cost causation and better match seasonal costs to seasonal revenues.

3. Rate stability and predictability. The proposed usage level rate designs incorporate more fixed charges and therefore result in more stable and more predictable bills to customers.

4. Static efficiency. The proposed usage level rate designs promote static efficiency by better reducing intra-class and seasonal subsidies than the Company's current declining block-based rate designs.

5. Incorporation of internalities and externalities. The proposed usage level rate design better meets this standard than the Company's current rate design because of its ability to provide better incentives to the utility to encourage energy efficient investments (thereby implicitly recognizing whatever pollution externalities might exist).

6. Fairness. Because it eliminates subsidies of all types and because it more accurately reflects the costs of service, the proposed usage level rate design better satisfies this standard than the Company's current rate design.

7. Avoidance of undue discrimination. Undue discrimination is avoided under the proposed usage level rate designs.

8. Dynamic efficiency. Dynamic efficiency is enhanced under the proposed usage level rate designs because they more closely track the costs of service.

9. Practicality. The practicality attributes favor the proposed rate design over the Company's current rate designs because the proposed usage level rate design incorporates far more certainty than the Company's current rate design.

In only one case does an evaluation of the two competing rate designs lead to no clear-cut winner:

10. Freedom from controversies as to proper interpretation. Both proposals are straightforward rate designs that customers are well accustomed to seeing and responding to.

IV. <u>PROOF OF REVENUE</u>

Q. HAVE YOU PREPARED A PROOF OF REVENUE TO SHOW THAT THE PROPOSED CGSA RECOMMENDED RATES MEET THE REQUIRED REVENUE ASSOCIATED WITH YOUR CLASS REVENUE ALLOCATION?

A. Yes. An arithmetical demonstration that the recommended proposed CGSA rates meet the assigned revenue for each class and for the entire service area is provided in Exhibit PHR-3. 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-3.

Q. HAVE YOU PREPARED A PROOF OF REVENUE TO SHOW THAT THE SEPARATE CTSA AND GCSA RECOMMENDED RATES MEET THE REQUIRED REVENUE ASSOCIATED WITH YOUR CLASS REVENUE ALLOCATIONS IN EACH AREA IF THE TWO SERVICE AREAS ARE NOT COMBINED?

A. Yes. The proof that the recommended GCSA and CTSA rates meet the assigned revenue for each class in each area is provided in Exhibit PHR-8 for the CTSA and Exhibit PHR-13 for the GCSA. These exhibits are based on separate rates for the CTSA and the GCSA based on the separate revenue requirements and class revenue allocations if consolidation of the two service areas is not approved.

V. <u>CUSTOMER BILL IMPACTS</u>

Q. HAVE YOU CALCULATED CUSTOMER BILL IMPACTS RESULTING FROM YOUR RECOMMENDED CGSA RATES?

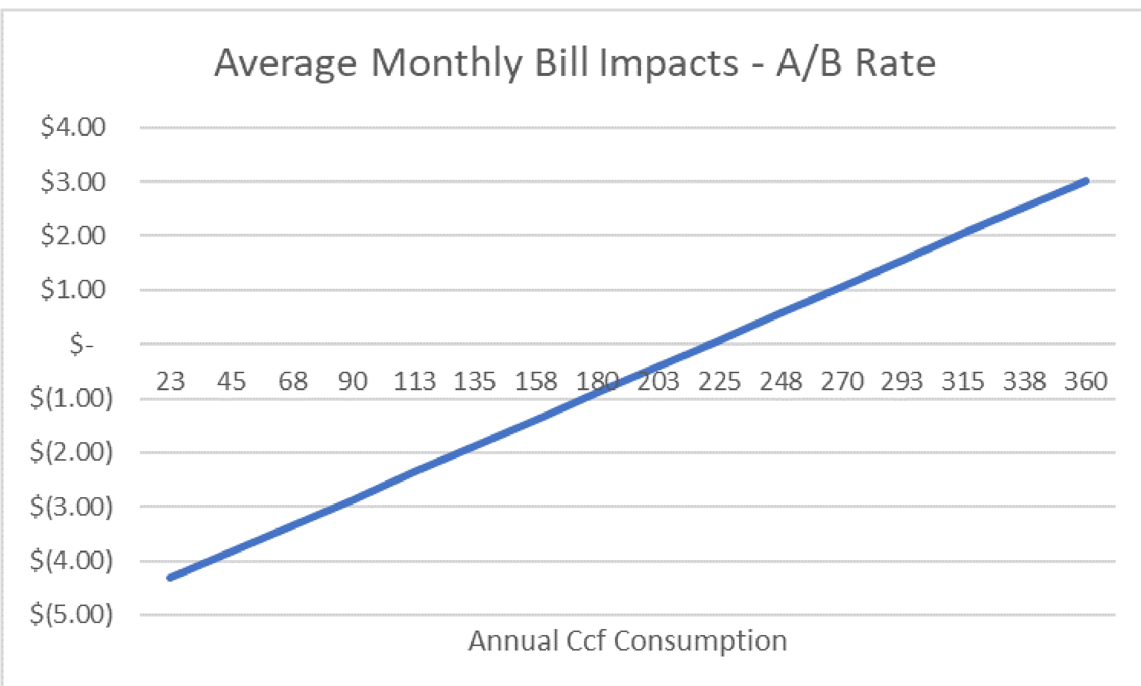
A. Yes. Exhibit PHR-4 provides proposed CGSA customer bill impacts for each service offering for average monthly usage and average January usage. The bills for sales service offerings are based on current and recommended rates and include the test year average cost of gas and applicable conservation adjustment tariff rates.

Q. PLEASE DESCRIBE HOW THE USAGE LEVEL RATE DESIGNS AVOID SIGNIFICANT RATE SHOCK.

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-5.

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 A/B rates. A better way to show the impact of the rate design change is to compare the proposed A/B 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-6 and shows that the rate design change is mitigating the rate increase by actually reducing bills below levels that they would be if the traditional rate design were continued for lower usage customers in the CTSA and GCSA Environs service areas. Even in the GCSA Incorporated areas, rate impacts as a result of the change in rate structure are modest, at most about $3/month rate for all users.

The following chart demonstrates this concept graphically:



As can be seen in the graph, the rate structure particularly benefits the lowest usage customers on the system.

Q. HAVE YOU CALCULATED CUSTOMER BILL IMPACTS RESULTING FROM YOUR RECOMMENDED SEPARATE CTSA AND GCSA RATES IF THE TWO SERVICE AREAS ARE NOT COMBINED?

A. Yes. If rates are to be designed separately for the CTSA and the GCSA based on the separate revenue requirements, Exhibit PHR-9 provides the CTSA customer bill impacts for each service offering for average monthly usage and average January usage. Exhibit PHR-14 provides the corresponding GCSA customer bill impacts. Consistent with the analysis of the Residential A/B rate options for the CGSA in Exhibit PHR-5 and Exhibit PHR-6, Exhibits PHR-10 and PHR-11 provide the detailed CTSA customer bill impacts for the Residential A/B rate design option and Exhibits PHR-15 and PHR-16 provide the corresponding GCSA customer bill impacts for the Residential A/B rate design option.

Q. DO YOU HAVE ANY 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 86% of the class resides in the CTSA and the remaining 14% in the GCSA. For the commercial sales class, approximately 87% resides in the CTSA and the remaining 13% in GCSA. For the public authority sales class, approximately 68% resides in CTSA, with the remaining 32% residing in the GCSA. All the industrial sales, public school space heating sales, irrigation sales and CNG sales customers reside in the CTSA. For all transportation customers, approximately 96% resides in the CTSA.

Furthermore, for all classes in the GCSA, bill impacts will be sizable no matter how rates are designed, although they will be much less for residential customers to the extent that an A/B rate structure is approved by the Commission.

Q. DO YOU HAVE ANY COMMENTS ON THE TRANSPORTATION CUSTOMER BILL IMPACTS SHOWN IN EXHIBIT PHR-4?

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 in Exhibit PHR-4 assume that transportation customers obtain their gas at a cost that is five% 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 COMMENTS ON THE TRANSPORTATION CUSTOMER BILL IMPACTS IF THE CONSOLIDATION OF THE CTSA AND GCSA IS NOT APPROVED?

A. Yes. If rates are to be designed separately for the CTSA and the GCSA based on the separate revenue requirements, if consolidation of the two service areas is not approved, Exhibits PHR-9 and PHR-14 provide transportation customer bill impacts in the CTSA and in the GCSA, respectively. As in Exhibit PHR-4, these bill impacts assume that transportation customers obtain their gas at a cost that is five% less than the Company's average gas cost in the test year.

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:

- o Texas Gas Service
- o Virginia Natural Gas
- o UGI Utilities, Inc. – Gas Division, UGI Penn Natural Gas, Inc., and UGI Central Penn Gas, Inc.
- o The Peoples Natural Gas Company d/b/a Dominion Peoples
- o National Fuel Gas Distribution Corporation
- o Columbia Gas of Pennsylvania, Inc.
- o Aquila
- o Kansas Corporation Commission
- o Atmos Energy Corporation
- o Electric Cooperatives' Association
- o Cleco
- o Washington Gas
- o Western Resources
- o Kansas Gas Service
- o 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 as a result 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 a number of 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:

- 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 a number of 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

- o 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:

- o Champaign Telephone Company
- o Plains Generation & Transmission Cooperative
- o CSX Corporation (Includes work for Seaboard Coast Line, Louisville & Nashville, Baltimore & Ohio, Chesapeake & Ohio, and Western Maryland Railroads)
- o Lea County Electric Cooperative, Inc.
- o North Carolina Electric Membership Cooperative
- o Alberta Gas Trunk Lines (NOVA)
- o 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
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
Georgia	18300-U	Costing/Rate Design
Indiana	36818	Capacity Planning

Jurisdiction	Docket Number	Subject
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
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
Louisiana	U-21453	Restructuring/Market Power

Jurisdiction	Docket Number	Subject
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
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
New Mexico	2087	Capacity Planning
	11-00042-UT	Rate Design
New York	27546	Costing/Rate Design
Ohio	81-1378-EL-AIR	Load Forecasting

Jurisdiction	Docket Number	Subject
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
Pennsylvania	R-0061346	Costing/Rate Design
	M-2009-2092222, M-2009-2112952, M-2009-2112956	Demand Side Planning
	M-2009-2093216	Demand Side Planning
	M-2009-2093217	Demand Side Planning
	M-2009-2093218	Demand Side Planning
	M-2010-2210316	Demand Side Planning
	R-2010-2214415	Demand Side Planning
	M-2012-2334387, M-2012-2334392, M-2012-2334398	Demand Side Planning
	M-2012-2334388	Demand Side Planning
	M-2015-2177174	Demand Side Planning
Tennessee	PURPA Hearings	Costing/Rate Design
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
US Tax Court	4870	Life Analysis
	4875	Life Analysis

Jurisdiction	Docket Number	Subject
Virginia	PUE900013	Demand Side Planning
	PUE920041	Costing/Rate Design
	PUE940030	Costing/Rate Design
	PUE940031	Costing/Rate Design
	PUE950131	Capacity Planning
	PUE980813	Costing/Rate Design
	PUE-2002-00364	Costing/Rate Design
	PUE-2003-00603	Costing/Rate Design
	PUE-2006-00059	Costing/Rate Design
	PUE-2008-00060	Demand Side Planning
	PUE-2009-00064	Demand Side Planning
	PUE-2012-00118	Demand Side Planning
	PUE-2015-00132	Demand Side Planning
	PUE-2015-00138	Demand Side Planning
	PUE-2016-00001	Capacity Planning
	PUR-2018-00080	Capacity Planning
	PUR-2018-00193	Demand Side Planning
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 is a member of 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 a number of professional journals and spoken at a number of 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.

- o "Estimating Implied Long- and Short-Run Price Elasticities of Natural Gas Consumption," Atlantic Economic Conference, Philadelphia, PA, October 10, 1993.

- o "Program Evaluation and Marginal Cost," The Natural Gas Least Cost Planning Conference, Washington, DC, April 7, 1992.

- o "The New Environmentalism & Least Cost Planning," Institute for Environmental Negotiation, University of Virginia, May 15, 1991.

- o "Development of Conditional Demand Estimates of Gas Appliances," AGA Forecasting Review, Vol. 1, No. 1, October 1988.

- o "The Feasibility Study: Forecasting and Sensitivities," Municipal Wastewater Treatment Facilities, The Energy Bureau, Inc., November 18, 1985.

- o "The Development of a Gas Sales End-Use Forecasting Model," Third International Forecasting Symposium, The International Institute of Forecasting, July 1984.

- o "New Forecasting Guidelines for REC's - A Seminar," (Chairman), Kansas City, Missouri, June 1984.

- o "A Method and Application of Estimating Long Run Marginal Cost for an Electric Utility," Advances in Microeconomics, Volume II, 1983.

- o "Forecasting Under Public Scrutiny," Forecasting Energy and Demand Requirements, University of Wisconsin - Extension, October 25, 1982.

- o "Forecasting Public Utilities," The Journal of Business Forecasting, Vol. 1, No. 4, Summer, 1982.

- o "Are Utilities Underforecasting," Electric Ratemaking, Vol. 1. No. 1, February, 1982.

- o "A Polynomial Spline Function Technique for Defining and Forecasting Electric Utility Load Duration Curves," First International Forecasting Symposium, Montreal, Canada, May, 1981.

- o "Time-of-Use Rates and Marginal Costs," ELCON Legal Seminar, March 20, l980.

- o "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.

CURRENT AND RECOMMENDED RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CURRENT AND RECOMMENDED RATES

Description		Current Rates				Recommended	
		CTSA Incorporated and Environs Rates	GCSA Incorporated Rates	GCSA Environs Rates	City of Beaumont Rates		
(a)		(b)	(c)	(d)	(e)	(f)	(g)
Residential						Rate Option A	Rate Option B
Customer Charge		$18.81	$12.42	$14.17	$12.10	$14.00	$27.58
Usage Rates	All Ccf	$0.12061	$0.45616	$0.40680	$0.45616	$0.55702	$0.10435
Commercial							
Customer Charge - Sales		$53.33	$51.11	$59.92	$49.49	$53.33	
Usage Rates	All Ccf	$0.11614				$0.12678	
	First 250		$0.22140	$0.20185	$0.22140		
	All Over 250		$0.19380	$0.17425	$0.19380		
Customer Charge - Transportation		$265.33	$297.11	$305.92		$265.33	
Usage Rates	All Ccf	$0.11614				$0.12678	
	First 250		0.22140	0.20185			
	All Over 250		0.19380	0.17425			
Industrial							
Customer Charge - Sales		$320.96	$153.41	$242.79		$320.96	
Usage Rates	All Ccf	$0.10273				$0.12703	
	First 250		$0.40060	$0.37808			
	All Over 250		$0.37480	$0.35228			
Customer Charge - Transportation		$520.96	$249.73	$432.79		$520.96	
Usage Rates	All Ccf	$0.10273				$0.12703	
	First 250		0.40060	0.37808			
	All Over 250		0.37480	0.35228			

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CURRENT AND RECOMMENDED RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CURRENT AND RECOMMENDED RATES

		Current Rates					
Description		CTSA Incorporated and Environs Rates	GCSA Incorporated Rates	GCSA Environs Rates	City of Beaumont Rates	Recommended	
(a)		(b)	(c)	(d)	(e)	(f)	(g)
Public Authority							
Customer Charge - Sales		$81.70	$106.10	$117.78		$81.70	
Usage Rates	All Ccf	$0.11541				$0.12551	
	First 250		$0.15672	$0.13587			
	All Over 250		$0.13092	$0.11007			
Customer Charge - Transportation		$104.70	$302.36	$307.78		$104.70	
Usage Rates	All Ccf	$0.11541				$0.12551	
	First 250		$0.15672	$0.13587			
	All Over 250		$0.13092	$0.11007			
Cogeneration							
Customer Charge - Sales		$104.70	NA	NA		$104.70	
Usage Rates	First 5,000 Ccf	$0.07720				$0.07720	
	Next 35,000	$0.06850				$0.06850	
	Next 60,000	$0.05524				$0.05524	
	All Over 100,000	$0.04016				$0.04016	
Customer Charge - Transportation		$104.70	NA	NA		$104.70	
Usage Rates	First 5,000 Ccf	$0.07720				$0.07720	
	Next 35,000	$0.06850				$0.06850	
	Next 60,000	$0.05524				$0.05524	
	All Over 100, 000	$0.04016				$0.04016	
Public Schools Space Heating							
Customer Charge - Sales		$134.70	NA	NA		$134.70	
Usage Rates	All Ccf	$0.10012				$0.10012	
Customer Charge - Transportation		$234.70	NA	NA		$234.70	
Usage Rates	All Ccf	$0.10012				$0.10012	
Compressed Natural Gas							
Customer Charge - Sales		$192.63	NA	NA		$192.63	
	All Ccf	$0.06684				$0.06684	
Customer Charge - Transportation		$217.63	NA	NA		$217.63	
	All Ccf	$0.06684				$0.06684	

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PROOF OF REVENUE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROOF OF REVENUE

Line	Description	Bills	Volumes		Recommended Rates Customer Charge	Recommended Rates Usage Charges	Calculated Revenue at Recommended Rates		Assigned Revenue	Rounding Diff.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Residential - Rate Option A	1,961,277			$ 14.00		$ 27,457,883			
2			All Ccf	35,289,483		0.55702	$ 19,656,948			
3	Residential - Rate Option B	1,566,691			$ 27.58		$ 43,209,348			
4			All Ccf	70,309,113		0.10435	$ 7,336,756			
5	Residential Total							$ 97,660,935	$ 97,660,663	$ 272
6										
7	Commercial	169,440			$ 53.33		$ 9,036,231			
8			All Ccf	44,493,619		0.12678	$ 5,640,901	$ 14,677,132		
9										
10	Commercial Transportation	4,385			$ 265.33		$ 1,163,507			
11			All Ccf	20,240,726		0.12678	$ 2,566,119	$ 3,729,627		
12										
13	Commercial Total							$ 18,406,759	$ 18,406,825	$ (66)
14										
15	Industrial	256			$ 320.96		$ 82,137			
16			All Ccf	656,316		0.12703	$ 83,372	$ 165,509		
17										
18	Industrial Transportation	444			$ 520.96		$ 231,306			
19			All Ccf	6,518,433		0.12703	$ 828,036	$ 1,059,343		
20										
21	Industrial Total							$ 1,224,851	$ 1,224,869	$ (17)
22										
23	Public Authority	9,971			$ 81.70		$ 814,624			
24			All Ccf	4,409,183		0.12551	$ 553,397	$ 1,368,021		
25										
26	Public Authority Transportation	4,681			$ 104.70		$ 490,101			
27			All Ccf	7,397,100		0.12551	$ 928,410	$ 1,418,511		
28										
29										

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PROOF OF REVENUE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROOF OF REVENUE

					Recommended Rates					
Line	Description	Bills	Volumes		Customer Charge	Usage Charges	Calculated Revenue at Recommended Rates		Assigned Revenue	Rounding Diff.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
30	COGEN Transportation	12			$ 104.70		$ 1,256			
31										
32			First 5000	60,000		0.07720	$ 4,632			
33			Next 35,000	420,000		0.06850	$ 28,770			
34			Next 60,000	720,000		0.05524	$ 39,773			
35			Over 100,000	2,685,983		0.04016	$ 107,869	$ 182,300		
36										
37	Public Schools Space Heating	65			$ 134.70		$ 8,709			
38			All Ccf	124,603		0.10012	12475.27645	$ 21,185		
39										
40	Public Schools Space Heating Transportation	980		-	$ 234.70		$ 230,006			
41			All Ccf	1,200,155		0.10012	$ 120,159	$ 350,165		
42										
43	Public Authority Total							$ 3,340,182	$ 3,340,229	$ (47)
44										
45	Compressed Nat. Gas	36			$ 192.63		$ 6,935			
46			All Ccf	620		0.06684	$ 41	$ 6,976		
47	Compressed Nat. Gas Transportation	48			$ 217.63		$ 10,446			
48			All Ccf	1,352,087		0.06684	$ 90,373	$ 100,820		
49	Compressed Nat. Gas Total							$ 107,796	$ 107,796	$ (0)
50										
51	Total Revenue - All Classes									
52	Recommended Rate Revenue							$ 120,740,523	$ 120,740,381	
53	Current Rate Revenue							$ 103,693,715	$ 103,693,715	
54	Revenue Change							$ 17,046,808	$ 17,046,666	$ 142
55	Schedule A - Revenue Deficiency								$ 17,046,666	

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CUSTOMER BILL IMPACTS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CUSTOMER BILL IMPACTS

	Year-Round Average Bill				Average January Bill			
			Change				Change	
Description	Current	Recommended	Dollars	%	Current	Recommended	$	%
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Sales Service: (1) (2)								
Residential - Rate Option A								
CTSA Incorporated	$ 29.20	$ 32.33	$ 3.13	10.7%	$ 46.74	$ 63.30	$ 16.56	35.4%
CTSA Environs	$ 29.20	$ 32.33	$ 3.13	10.7%	$ 46.74	$ 63.30	$ 16.56	35.4%
GCSA Incorporated	$ 29.57	$ 32.33	$ 2.76	9.3%	$ 58.55	$ 63.30	$ 4.75	8.1%
GCSA Environs	$ 30.44	$ 32.33	$ 1.89	6.2%	$ 57.91	$ 63.30	$ 5.39	9.3%
City of Beaumont	$ 29.25	$ 32.33	$ 3.08	10.5%	$ 58.23	$ 63.30	$ 5.07	8.7%
Residential - Rate Option B								
CTSA Incorporated	$ 44.71	$ 52.99	$ 8.28	18.5%	$ 88.47	$ 95.91	$ 7.44	8.4%
CTSA Environs	$ 44.71	$ 52.99	$ 8.28	18.5%	$ 88.47	$ 95.91	$ 7.44	8.4%
GCSA Incorporated	$ 55.21	$ 52.99	$ (2.22)	-4.0%	$ 127.48	$ 95.91	$ (31.57)	-24.8%
GCSA Environs	$ 54.74	$ 52.99	$ (1.75)	-3.2%	$ 123.27	$ 95.91	$ (27.36)	-22.2%
City of Beaumont	$ 54.89	$ 52.99	$ (1.90)	-3.5%	$ 127.16	$ 95.91	$ (31.25)	-24.6%
Commercial								
CTSA Incorporated	$ 203.72	$ 207.89	$ 4.17	2.0%	$ 305.97	$ 312.96	$ 6.99	2.3%
CTSA Environs	$ 203.72	$ 207.89	$ 4.17	2.0%	$ 305.97	$ 312.96	$ 6.99	2.3%
GCSA Incorporated	$ 239.47	$ 207.89	$ (31.58)	-13.2%	$ 362.83	$ 312.96	$ (49.87)	-13.7%
GCSA Environs	$ 243.14	$ 207.89	$ (35.25)	-14.5%	$ 363.02	$ 312.96	$ (50.06)	-13.8%
City of Beaumont	$ 237.85	$ 207.89	$ (29.96)	-12.6%	$ 361.21	$ 312.96	$ (48.25)	-13.4%
Industrial								
CTSA Incorporated and Environs	$ 1,755.39	$ 1,831.10	$ 75.71	4.3%	$ 3,245.01	$ 3,399.34	$ 154.33	4.8%
Public Authority								
CTSA Incorporated and Environs	$ 334.64	$ 341.41	$ 6.77	2.0%	$ 655.03	$ 670.39	$ 15.36	2.3%
GCSA Incorporated	$ 390.32	$ 341.41	$ (48.91)	-12.5%	$ 742.16	$ 670.39	$ (71.77)	-9.7%
GCSA Environs	$ 392.78	$ 341.41	$ (51.37)	-13.1%	$ 732.94	$ 670.39	$ (62.55)	-8.5%
Public Schools Space Heating								
CTSA Incorporated and Environs	$ 1,207.53	$ 1,217.59	$ 10.06	0.8%	$ 1,412.18	$ 1,424.16	$ 11.98	0.8%
Compressed Natural Gas								
CTSA Incorporated	$ 201.64	$ 201.73	$ 0.09	0.0%	$ 208.34	$ 208.50	$ 0.16	0.1%

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CUSTOMER BILL IMPACTS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CUSTOMER BILL IMPACTS

	Year-Round Average Bill				Average January Bill			
			Change				Change	
Description	Current	Recommended	Dollars	%	Current	Recommended	$	%
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Transportation Service: (3)								
Commercial Transportation								
CTSA Incorporated	$ 2,803.50	$ 2,875.50	$ 72.00	2.6%	$ 3,416.06	$ 3,505.44	$ 89.38	2.6%
CTSA Environs	$ 2,803.50	$ 2,875.50	$ 72.00	2.6%	$ 3,416.06	$ 3,505.44	$ 89.38	2.6%
GCSA Incorporated	$ 3,378.83	$ 2,875.50	$ (503.33)	-14.9%	$ 4,120.91	$ 3,505.44	$ (615.47)	-14.9%
Industrial Transportation								
CTSA Incorporated and Environs	$ 8,397.14	$ 8,826.68	$ 429.54	5.1%	$ 9,410.89	$ 9,895.73	$ 484.84	5.2%
GCSA Incorporated	$ 12,693.43	$ 8,826.68	$ (3,866.75)	-30.5%	$ 14,294.25	$ 9,895.73	$ (4,398.52)	-30.8%
Public Authority Transportation								
CTSA Incorporated and Environs	$ 972.51	$ 996.30	$ 23.79	2.4%	$ 1,382.92	$ 1,417.97	$ 35.05	2.5%
Public School Space Heating Transportation								
CTSA Incorporated and Environs	$ 888.51	$ 894.58	$ 6.07	0.7%	$ 1,404.61	$ 1,415.47	$ 10.86	0.8%
Cogeneration Transportation (4)								
CTSA Incorporated	$ 155,654.46	$ 157,260.17	$ 1,605.71	1.0%	$ 163,214.82	$ 164,899.63	$ 1,684.81	1.0%
Compressed Natural Gas Transportation								
CTSA Incorporated and Environs	$ 14,318.55	$ 14,458.22	$ 139.67	1.0%	$ 13,331.27	$ 13,461.16	$ 129.89	1.0%

Exhibit PHR-4
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CUSTOMER BILL IMPACTS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CUSTOMER BILL IMPACTS

	Year-Round Average Bill				Average January Bill			
			Change				Change	
Description	Current	Recommended	Dollars	%	Current	Recommended	$	%
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)

(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:

	CGSA	
	Year-Round	January
Residential - Rate Option A	18	48
Residential - Rate Option B	45	121
Commercial	263	441
Industrial	2,565	5,228
Public Authority	442	1,002
Public School Space Heating	1,927	2,295
Compressed Natural Gas	17	30

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

	CGSA	
	Year-Round	January
Commercial Transportation	4,616	5,730
Industrial Transportation	14,681	16,571
Public Authority Transportation	1,580	2,328
Public School Space Heating Transportation	1,225	2,191
Compressed Natural Gas Transportation	28,168	26,196
	August	January
Cogeneration Transportation	339,785	323,832

(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.

Exhibit PHR-4
Page 3 of 3

A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of CGSA A/B Rate Relative to Existing CTSA Rates

								$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 18.81	$ 0.12061	$ 0.12061			$ 27.58	$ 0.10435	$ 0.10435	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	23	2,085	225.72	-	2.71	225.72	228.43	168.00	-	12.53	168.00	180.53	(4.81)	(3.99)	-26%	-21%
24	45	2,006	225.72	2.83	5.43	228.55	231.15	168.00	13.09	25.07	181.09	193.07	(3.96)	(3.17)	-21%	-16%
46	68	2,578	225.72	5.55	8.14	231.27	233.86	168.00	25.62	37.60	193.62	205.60	(3.14)	(2.36)	-16%	-12%
69	90	3,693	225.72	8.26	10.85	233.98	236.57	168.00	38.16	50.13	206.16	218.13	(2.32)	(1.54)	-12%	-8%
91	113	4,722	225.72	10.98	13.57	236.70	239.29	168.00	50.69	62.66	218.69	230.66	(1.50)	(0.72)	-8%	-4%
114	135	6,110	225.72	13.69	16.28	239.41	242.00	168.00	63.22	75.20	231.22	243.20	(0.68)	0.10	-3%	0%
136	158	7,285	225.72	16.40	19.00	242.12	244.72	168.00	75.75	87.73	243.75	255.73	0.14	0.92	1%	5%
159	180	8,522	225.72	19.12	21.71	244.84	247.43	168.00	88.29	100.26	256.29	268.26	0.95	1.74	5%	8%
181	203	10,021	225.72	21.83	24.42	247.55	250.14	168.00	100.82	112.80	268.82	280.80	1.77	2.55	9%	12%
204	225	11,477	225.72	24.54	27.14	250.26	252.86	168.00	113.35	125.33	281.35	293.33	2.59	3.37	12%	16%
226	248	12,263	225.72	27.26	29.85	252.98	255.57	168.00	125.89	137.86	293.89	305.86	3.41	4.19	16%	20%
249	270	13,208	225.72	29.97	32.56	255.69	258.28	168.00	138.42	150.40	306.42	318.40	4.23	5.01	20%	23%
271	293	13,691	225.72	32.69	35.28	258.41	261.00	168.00	150.95	162.93	318.95	330.93	5.05	5.83	23%	27%
294	315	13,818	225.72	35.40	37.99	261.12	263.71	168.00	163.49	175.46	331.49	343.46	5.86	6.65	27%	30%
316	338	13,485	225.72	38.11	40.71	263.83	266.43	168.00	176.02	187.99	344.02	355.99	6.68	7.46	30%	34%
339	360	12,886	225.72	40.83	43.42	266.55	269.14	168.00	188.55	200.53	356.55	368.53	7.50	8.28	34%	37%
361	586	78,801	225.72	43.54	70.65	269.26	296.37	330.96	37.67	61.12	368.63	392.08	8.28	7.98	37%	32%
587	812	23,302	225.72	70.77	97.88	296.49	323.60	330.96	61.23	84.68	392.19	415.64	7.97	7.67	32%	28%
813	1,037	6,767	225.72	98.00	125.11	323.72	350.83	330.96	84.79	108.24	415.75	439.20	7.67	7.36	28%	25%
1,038	1,263	2,333	225.72	125.23	152.34	350.95	378.06	330.96	108.35	131.80	439.31	462.76	7.36	7.06	25%	22%
1,264	1,489	1,062	225.72	152.46	179.57	378.18	405.29	330.96	131.90	155.36	462.86	486.32	7.06	6.75	22%	20%
1,490	1,715	585	225.72	179.69	206.79	405.41	432.51	330.96	155.46	178.92	486.42	509.88	6.75	6.45	20%	18%
1,716	1,940	316	225.72	206.92	234.02	432.64	459.74	330.96	179.02	202.47	509.98	533.43	6.45	6.14	18%	16%
1,941	2,166	185	225.72	234.14	261.25	459.86	486.97	330.96	202.58	226.03	533.54	556.99	6.14	5.83	16%	14%
2,167	2,392	122	225.72	261.37	288.48	487.09	514.20	330.96	226.14	249.59	557.10	580.55	5.83	5.53	14%	13%
2,393	2,618	101	225.72	288.60	315.71	514.32	541.43	330.96	249.69	273.15	580.65	604.11	5.53	5.22	13%	12%
2,619	2,843	69	225.72	315.83	342.94	541.55	568.66	330.96	273.25	296.71	604.21	627.67	5.22	4.92	12%	10%
2,844	3,069	41	225.72	343.06	370.17	568.78	595.89	330.96	296.81	320.27	627.77	651.23	4.92	4.61	10%	9%
3,070	3,295	45	225.72	370.29	397.40	596.01	623.12	330.96	320.37	343.82	651.33	674.78	4.61	4.31	9%	8%
3,296	3,521	22	225.72	397.52	424.63	623.24	650.35	330.96	343.93	367.38	674.89	698.34	4.30	4.00	8%	7%
3,522	8,262	70	225.72	424.75	996.44	650.47	1,222.16	330.96	367.49	862.11	698.45	1,193.07	4.00	(2.42)	7%	-2%

A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of CGSA A/B Rate Relative to Existing GCSA Incorporated Rates

								$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 12.42	$ 0.45616	$ 0.45616		0	$ 27.58	$ 0.10435	$ 0.10435	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	23	1,478	$ 149.04	$ -	$ 10.26	$ 149.04	$ 159.30	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ 1.58	$ 1.77	13%	13%
24	45	844	$ 149.04	$ 10.72	$ 20.53	$ 159.76	$ 169.57	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ 1.78	$ 1.96	13%	14%
46	68	1,024	$ 149.04	$ 20.98	$ 30.79	$ 170.02	$ 179.83	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ 1.97	$ 2.15	14%	14%
69	90	1,014	$ 149.04	$ 31.25	$ 41.05	$ 180.29	$ 190.09	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ 2.16	$ 2.34	14%	15%
91	113	1,154	$ 149.04	$ 41.51	$ 51.32	$ 190.55	$ 200.36	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ 2.34	$ 2.53	15%	15%
114	135	1,229	$ 149.04	$ 51.77	$ 61.58	$ 200.81	$ 210.62	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ 2.53	$ 2.71	15%	15%
136	158	1,350	$ 149.04	$ 62.04	$ 71.85	$ 211.08	$ 220.89	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ 2.72	$ 2.90	15%	16%
159	180	1,545	$ 149.04	$ 72.30	$ 82.11	$ 221.34	$ 231.15	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ 2.91	$ 3.09	16%	16%
181	203	1,663	$ 149.04	$ 82.56	$ 92.37	$ 231.60	$ 241.41	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ 3.10	$ 3.28	16%	16%
204	225	1,806	$ 149.04	$ 92.83	$ 102.64	$ 241.87	$ 251.68	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ 3.29	$ 3.47	16%	17%
226	248	1,965	$ 149.04	$ 103.09	$ 112.90	$ 252.13	$ 261.94	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 3.48	$ 3.66	17%	17%
249	270	1,976	$ 149.04	$ 113.36	$ 123.16	$ 262.40	$ 272.20	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 3.67	$ 3.85	17%	17%
271	293	2,013	$ 149.04	$ 123.62	$ 133.43	$ 272.66	$ 282.47	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 3.86	$ 4.04	17%	17%
294	315	2,080	$ 149.04	$ 133.88	$ 143.69	$ 282.92	$ 292.73	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 4.05	$ 4.23	17%	17%
316	338	1,911	$ 149.04	$ 144.15	$ 153.95	$ 293.19	$ 302.99	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 4.24	$ 4.42	17%	17%
339	360	1,835	$ 149.04	$ 154.41	$ 164.22	$ 303.45	$ 313.26	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 4.43	$ 4.61	17%	18%
361	468	7,278	$ 149.04	$ 164.67	$ 213.62	$ 313.71	$ 362.66	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 4.58	$ 1.43	18%	5%
469	577	4,181	$ 149.04	$ 214.08	$ 263.02	$ 363.12	$ 412.06	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.40	$ (1.74)	5%	-5%
578	685	2,250	$ 149.04	$ 263.48	$ 312.43	$ 412.52	$ 461.47	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (1.77)	$ (4.92)	-5%	-13%
686	793	1,222	$ 149.04	$ 312.88	$ 361.83	$ 461.92	$ 510.87	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (4.95)	$ (8.09)	-13%	-19%
794	902	593	$ 149.04	$ 362.29	$ 411.23	$ 511.33	$ 560.27	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (8.12)	$ (11.27)	-19%	-24%
903	1010	285	$ 149.04	$ 411.69	$ 460.64	$ 560.73	$ 609.68	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (11.30)	$ (14.45)	-24%	-28%
1,011	1118	188	$ 149.04	$ 461.09	$ 510.04	$ 610.13	$ 659.08	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (14.47)	$ (17.62)	-28%	-32%
1,119	1226	92	$ 149.04	$ 510.50	$ 559.45	$ 659.54	$ 708.49	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (17.65)	$ (20.80)	-32%	-35%
1,227	1335	60	$ 149.04	$ 559.90	$ 608.85	$ 708.94	$ 757.89	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (20.82)	$ (23.97)	-35%	-38%
1,336	1443	36	$ 149.04	$ 609.30	$ 658.25	$ 758.34	$ 807.29	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (24.00)	$ (27.15)	-38%	-40%
1,444	1551	21	$ 149.04	$ 658.71	$ 707.66	$ 807.75	$ 856.70	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (27.18)	$ (30.32)	-40%	-42%
1,552	1660	16	$ 149.04	$ 708.11	$ 757.06	$ 857.15	$ 906.10	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (30.35)	$ (33.50)	-42%	-44%
1,661	1768	11	$ 149.04	$ 757.51	$ 806.46	$ 906.55	$ 955.50	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (33.53)	$ (36.67)	-44%	-46%
1,769	1876	22	$ 149.04	$ 806.92	$ 855.87	$ 955.96	$ 1,004.91	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (36.70)	$ (39.85)	-46%	-48%
1,877	4151	41	$ 149.04	$ 856.32	$ 1,893.34	$ 1,005.36	$ 2,042.38	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (39.88)	$ (106.53)	-48%	-63%

A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of CGSA A/B Rate Relative to Existing GCSA Environs Rates

								$ 14.00	$ 0.55702	$ 0.55702 Res A						
			$ 14.17	$ 0.40680	$ 0.40680			$ 27.58	$ 0.10435	$ 0.10435 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	23	41	$ 170.04	$ -	$ 9.15	$ 170.04	$ 179.19	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ (0.17)	$ 0.11	-1%	1%
24	45	23	$ 170.04	$ 9.56	$ 18.31	$ 179.60	$ 188.35	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ 0.12	$ 0.39	1%	3%
46	68	28	$ 170.04	$ 18.71	$ 27.46	$ 188.75	$ 197.50	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ 0.41	$ 0.67	3%	4%
69	90	28	$ 170.04	$ 27.87	$ 36.61	$ 197.91	$ 206.65	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ 0.69	$ 0.96	4%	6%
91	113	32	$ 170.04	$ 37.02	$ 45.77	$ 207.06	$ 215.81	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ 0.97	$ 1.24	6%	7%
114	135	34	$ 170.04	$ 46.17	$ 54.92	$ 216.21	$ 224.96	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ 1.25	$ 1.52	7%	8%
136	158	37	$ 170.04	$ 55.32	$ 64.07	$ 225.36	$ 234.11	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ 1.53	$ 1.80	8%	9%
159	180	43	$ 170.04	$ 64.48	$ 73.22	$ 234.52	$ 243.26	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ 1.81	$ 2.08	9%	10%
181	203	46	$ 170.04	$ 73.63	$ 82.38	$ 243.67	$ 252.42	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ 2.10	$ 2.36	10%	11%
204	225	50	$ 170.04	$ 82.78	$ 91.53	$ 252.82	$ 261.57	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ 2.38	$ 2.65	11%	12%
226	248	55	$ 170.04	$ 91.94	$ 100.68	$ 261.98	$ 270.72	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 2.66	$ 2.93	12%	13%
249	270	55	$ 170.04	$ 101.09	$ 109.84	$ 271.13	$ 279.88	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 2.94	$ 3.21	13%	14%
271	293	56	$ 170.04	$ 110.24	$ 118.99	$ 280.28	$ 289.03	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 3.22	$ 3.49	14%	14%
294	315	58	$ 170.04	$ 119.40	$ 128.14	$ 289.44	$ 298.18	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 3.50	$ 3.77	15%	15%
316	338	53	$ 170.04	$ 128.55	$ 137.30	$ 298.59	$ 307.34	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 3.79	$ 4.05	15%	16%
339	360	51	$ 170.04	$ 137.70	$ 146.45	$ 307.74	$ 316.49	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 4.07	$ 4.34	16%	16%
361	468	202	$ 170.04	$ 146.85	$ 190.51	$ 316.89	$ 360.55	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 4.31	$ 1.61	16%	5%
469	577	116	$ 170.04	$ 190.91	$ 234.56	$ 360.95	$ 404.60	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.58	$ (1.12)	5%	-3%
578	685	62	$ 170.04	$ 234.97	$ 278.62	$ 405.01	$ 448.66	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (1.15)	$ (3.85)	-3%	-10%
686	793	34	$ 170.04	$ 279.03	$ 322.68	$ 449.07	$ 492.72	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (3.88)	$ (6.58)	-10%	-16%
794	902	16	$ 170.04	$ 323.09	$ 366.74	$ 493.13	$ 536.78	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (6.61)	$ (9.31)	-16%	-21%
903	1010	8	$ 170.04	$ 367.14	$ 410.79	$ 537.18	$ 580.83	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (9.34)	$ (12.04)	-21%	-25%
1,011	1118	5	$ 170.04	$ 411.20	$ 454.85	$ 581.24	$ 624.89	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (12.07)	$ (14.77)	-25%	-28%
1,119	1226	3	$ 170.04	$ 455.26	$ 498.91	$ 625.30	$ 668.95	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (14.80)	$ (17.50)	-28%	-31%
1,227	1335	2	$ 170.04	$ 499.32	$ 542.97	$ 669.36	$ 713.01	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (17.53)	$ (20.23)	-31%	-34%
1,336	1443	1	$ 170.04	$ 543.37	$ 587.02	$ 713.41	$ 757.06	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (20.26)	$ (22.96)	-34%	-36%
1,444	1551	1	$ 170.04	$ 587.43	$ 631.08	$ 757.47	$ 801.12	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (22.99)	$ (25.69)	-36%	-38%
1,552	1660	0	$ 170.04	$ 631.49	$ 675.14	$ 801.53	$ 845.18	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (25.72)	$ (28.42)	-38%	-40%
1,661	1768	0	$ 170.04	$ 675.55	$ 719.20	$ 845.59	$ 889.24	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (28.44)	$ (31.15)	-40%	-42%
1,769	1876	1	$ 170.04	$ 719.60	$ 763.25	$ 889.64	$ 933.29	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (31.17)	$ (33.88)	-42%	-44%
1,877	4151	1	$ 170.04	$ 763.66	$ 1,688.46	$ 933.70	$ 1,858.50	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (33.90)	$ (91.20)	-44%	-59%

A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of CGSA A/B Rate Relative to Existing City of Beaumont Rates

								$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 12.10	$ 0.45616	$ 0.45616			$ 27.58	$ 0.10435	$ 0.10435	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	23	-	$ 145.20	$ -	$ 10.26	$ 145.20	$ 155.46	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ 1.90	$ 2.09	16%	16%
24	45	-	$ 145.20	$ 10.72	$ 20.53	$ 155.92	$ 165.73	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ 2.10	$ 2.28	16%	16%
46	68	-	$ 145.20	$ 20.98	$ 30.79	$ 166.18	$ 175.99	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ 2.29	$ 2.47	17%	17%
69	90	-	$ 145.20	$ 31.25	$ 41.05	$ 176.45	$ 186.25	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ 2.48	$ 2.66	17%	17%
91	113	-	$ 145.20	$ 41.51	$ 51.32	$ 186.71	$ 196.52	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ 2.66	$ 2.85	17%	17%
114	135	-	$ 145.20	$ 51.77	$ 61.58	$ 196.97	$ 206.78	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ 2.85	$ 3.03	17%	18%
136	158	-	$ 145.20	$ 62.04	$ 71.85	$ 207.24	$ 217.05	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ 3.04	$ 3.22	18%	18%
159	180	-	$ 145.20	$ 72.30	$ 82.11	$ 217.50	$ 227.31	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ 3.23	$ 3.41	18%	18%
181	203	-	$ 145.20	$ 82.56	$ 92.37	$ 227.76	$ 237.57	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ 3.42	$ 3.60	18%	18%
204	225	-	$ 145.20	$ 92.83	$ 102.64	$ 238.03	$ 247.84	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ 3.61	$ 3.79	18%	18%
226	248	-	$ 145.20	$ 103.09	$ 112.90	$ 248.29	$ 258.10	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 3.80	$ 3.98	18%	19%
249	270	-	$ 145.20	$ 113.36	$ 123.16	$ 258.56	$ 268.36	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 3.99	$ 4.17	19%	19%
271	293	-	$ 145.20	$ 123.62	$ 133.43	$ 268.82	$ 278.63	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 4.18	$ 4.36	19%	19%
294	315	-	$ 145.20	$ 133.88	$ 143.69	$ 279.08	$ 288.89	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 4.37	$ 4.55	19%	19%
316	338	1	$ 145.20	$ 144.15	$ 153.95	$ 289.35	$ 299.15	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 4.56	$ 4.74	19%	19%
339	360	-	$ 145.20	$ 154.41	$ 164.22	$ 299.61	$ 309.42	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 4.75	$ 4.93	19%	19%
361	468	-	$ 145.20	$ 164.67	$ 213.62	$ 309.87	$ 358.82	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 4.90	$ 1.75	19%	6%
469	577	-	$ 145.20	$ 214.08	$ 263.02	$ 359.28	$ 408.22	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.72	$ (1.42)	6%	-4%
578	685	-	$ 145.20	$ 263.48	$ 312.43	$ 408.68	$ 457.63	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (1.45)	$ (4.60)	-4%	-12%
686	793	-	$ 145.20	$ 312.88	$ 361.83	$ 458.08	$ 507.03	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (4.63)	$ (7.77)	-12%	-18%
794	902	-	$ 145.20	$ 362.29	$ 411.23	$ 507.49	$ 556.43	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (7.80)	$ (10.95)	-18%	-24%
903	1010	-	$ 145.20	$ 411.69	$ 460.64	$ 556.89	$ 605.84	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (10.98)	$ (14.13)	-24%	-28%
1,011	1118	-	$ 145.20	$ 461.09	$ 510.04	$ 606.29	$ 655.24	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (14.15)	$ (17.30)	-28%	-32%
1,119	1226	-	$ 145.20	$ 510.50	$ 559.45	$ 655.70	$ 704.65	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (17.33)	$ (20.48)	-32%	-35%
1,227	1335	-	$ 145.20	$ 559.90	$ 608.85	$ 705.10	$ 754.05	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (20.50)	$ (23.65)	-35%	-38%
1,336	1443	-	$ 145.20	$ 609.30	$ 658.25	$ 754.50	$ 803.45	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (23.68)	$ (26.83)	-38%	-40%
1,444	1551	-	$ 145.20	$ 658.71	$ 707.66	$ 803.91	$ 852.86	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (26.86)	$ (30.00)	-40%	-42%
1,552	1660	-	$ 145.20	$ 708.11	$ 757.06	$ 853.31	$ 902.26	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (30.03)	$ (33.18)	-42%	-44%
1,661	1768	-	$ 145.20	$ 757.51	$ 806.46	$ 902.71	$ 951.66	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (33.21)	$ (36.35)	-44%	-46%
1,769	1876	-	$ 145.20	$ 806.92	$ 855.87	$ 952.12	$ 1,001.07	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (36.38)	$ (39.53)	-46%	-47%
1,877	4151	-	$ 145.20	$ 856.32	$ 1,893.34	$ 1,001.52	$ 2,038.54	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (39.56)	$ (106.21)	-47%	-63%

A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADIONAL RATE STRUCTURE

Annual Residential Bill Impacts of CGSA A/B Rate Structure in CTSA Compared to Traditional Rate Structure

								$ 14.00	$ 0.55702	$ 0.55702 Res A						
			$ 18.81	$ 0.29640	$ 0.29640			$ 27.58	$ 0.10435	$ 0.10435 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	23	2,085	$ 225.72	$ -	$ 6.67	$ 225.72	$ 232.39	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ (4.81)	$ (4.32)	-26%	-22%
24	45	2,006	$ 225.72	$ 6.97	$ 13.34	$ 232.69	$ 239.06	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ (4.30)	$ (3.83)	-22%	-19%
46	68	2,578	$ 225.72	$ 13.63	$ 20.01	$ 239.35	$ 245.73	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ (3.81)	$ (3.34)	-19%	-16%
69	90	3,693	$ 225.72	$ 20.30	$ 26.68	$ 246.02	$ 252.40	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ (3.32)	$ (2.86)	-16%	-14%
91	113	4,722	$ 225.72	$ 26.97	$ 33.35	$ 252.69	$ 259.07	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ (2.83)	$ (2.37)	-13%	-11%
114	135	6,110	$ 225.72	$ 33.64	$ 40.01	$ 259.36	$ 265.73	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ (2.34)	$ (1.88)	-11%	-8%
136	158	7,285	$ 225.72	$ 40.31	$ 46.68	$ 266.03	$ 272.40	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ (1.86)	$ (1.39)	-8%	-6%
159	180	8,522	$ 225.72	$ 46.98	$ 53.35	$ 272.70	$ 279.07	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ (1.37)	$ (0.90)	-6%	-4%
181	203	10,021	$ 225.72	$ 53.65	$ 60.02	$ 279.37	$ 285.74	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ (0.88)	$ (0.41)	-4%	-2%
204	225	11,477	$ 225.72	$ 60.32	$ 66.69	$ 286.04	$ 292.41	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ (0.39)	$ 0.08	-2%	0%
226	248	12,263	$ 225.72	$ 66.99	$ 73.36	$ 292.71	$ 299.08	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 0.10	$ 0.57	0%	2%
249	270	13,208	$ 225.72	$ 73.66	$ 80.03	$ 299.38	$ 305.75	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 0.59	$ 1.05	2%	4%
271	293	13,691	$ 225.72	$ 80.32	$ 86.70	$ 306.04	$ 312.42	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 1.08	$ 1.54	4%	6%
294	315	13,818	$ 225.72	$ 86.99	$ 93.37	$ 312.71	$ 319.09	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 1.56	$ 2.03	6%	8%
316	338	13,485	$ 225.72	$ 93.66	$ 100.04	$ 319.38	$ 325.76	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 2.05	$ 2.52	8%	9%
339	360	12,886	$ 225.72	$ 100.33	$ 106.70	$ 326.05	$ 332.42	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 2.54	$ 3.01	9%	11%
361	586	78,801	$ 225.72	$ 107.00	$ 173.62	$ 332.72	$ 399.34	$ 330.96	$ 37.67	$ 61.12	$ 368.63	$ 392.08	$ 2.99	$ (0.60)	11%	-2%
587	812	23,302	$ 225.72	$ 173.92	$ 240.54	$ 399.64	$ 466.26	$ 330.96	$ 61.23	$ 84.68	$ 392.19	$ 415.64	$ (0.62)	$ (4.22)	-2%	-11%
813	1,037	6,767	$ 225.72	$ 240.83	$ 307.45	$ 466.55	$ 533.17	$ 330.96	$ 84.79	$ 108.24	$ 415.75	$ 439.20	$ (4.23)	$ (7.83)	-11%	-18%
1,038	1,263	2,333	$ 225.72	$ 307.75	$ 374.37	$ 533.47	$ 600.09	$ 330.96	$ 108.35	$ 131.80	$ 439.31	$ 462.76	$ (7.85)	$ (11.44)	-18%	-23%
1,264	1,489	1,062	$ 225.72	$ 374.66	$ 441.28	$ 600.38	$ 667.00	$ 330.96	$ 131.90	$ 155.36	$ 462.86	$ 486.32	$ (11.46)	$ (15.06)	-23%	-27%
1,490	1,715	585	$ 225.72	$ 441.58	$ 508.20	$ 667.30	$ 733.92	$ 330.96	$ 155.46	$ 178.92	$ 486.42	$ 509.88	$ (15.07)	$ (18.67)	-27%	-31%
1,716	1,940	316	$ 225.72	$ 508.50	$ 575.11	$ 734.22	$ 800.83	$ 330.96	$ 179.02	$ 202.47	$ 509.98	$ 533.43	$ (18.69)	$ (22.28)	-31%	-33%
1,941	2,166	185	$ 225.72	$ 575.41	$ 642.03	$ 801.13	$ 867.75	$ 330.96	$ 202.58	$ 226.03	$ 533.54	$ 556.99	$ (22.30)	$ (25.90)	-33%	-36%
2,167	2,392	122	$ 225.72	$ 642.33	$ 708.95	$ 868.05	$ 934.67	$ 330.96	$ 226.14	$ 249.59	$ 557.10	$ 580.55	$ (25.91)	$ (29.51)	-36%	-38%
2,393	2,618	101	$ 225.72	$ 709.24	$ 775.86	$ 934.96	$ 1,001.58	$ 330.96	$ 249.69	$ 273.15	$ 580.65	$ 604.11	$ (29.53)	$ (33.12)	-38%	-40%
2,619	2,843	69	$ 225.72	$ 776.16	$ 842.78	$ 1,001.88	$ 1,068.50	$ 330.96	$ 273.25	$ 296.71	$ 604.21	$ 627.67	$ (33.14)	$ (36.74)	-40%	-41%
2,844	3,069	41	$ 225.72	$ 843.07	$ 909.69	$ 1,068.79	$ 1,135.41	$ 330.96	$ 296.81	$ 320.27	$ 627.77	$ 651.23	$ (36.75)	$ (40.35)	-41%	-43%
3,070	3,295	45	$ 225.72	$ 909.99	$ 976.61	$ 1,135.71	$ 1,202.33	$ 330.96	$ 320.37	$ 343.82	$ 651.33	$ 674.78	$ (40.37)	$ (43.96)	-43%	-44%
3,296	3,521	22	$ 225.72	$ 976.91	$ 1,043.53	$ 1,202.63	$ 1,269.25	$ 330.96	$ 343.93	$ 367.38	$ 674.89	$ 698.34	$ (43.98)	$ (47.58)	-44%	-45%
3,522	8,262	70	$ 225.72	$ 1,043.82	$ 2,448.76	$ 1,269.54	$ 2,674.48	$ 330.96	$ 367.49	$ 862.11	$ 698.45	$ 1,193.07	$ (47.59)	$ (123.45)	-45%	-55%

Exhibit PHR-6
Page 1 of 4

A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADIONAL RATE STRUCTURE

Annual Residential Bill Impacts of CGSA A/B Rate Structure in GCSA Incorporated Compared to Traditional Rate Structure

									$ 14.00	$ 0.55702	$ 0.55702	Res A				
			$ 18.81	$ 0.29640	$ 0.29640			0	$ 27.58	$ 0.10435	$ 0.10435	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	23	1,478	$ 225.72	$ -	$ 6.67	$ 225.72	$ 232.39	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ (4.81)	$ (4.32)	-26%	-22%
24	45	844	$ 225.72	$ 6.97	$ 13.34	$ 232.69	$ 239.06	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ (4.30)	$ (3.83)	-22%	-19%
46	68	1,024	$ 225.72	$ 13.63	$ 20.01	$ 239.35	$ 245.73	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ (3.81)	$ (3.34)	-19%	-16%
69	90	1,014	$ 225.72	$ 20.30	$ 26.68	$ 246.02	$ 252.40	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ (3.32)	$ (2.86)	-16%	-14%
91	113	1,154	$ 225.72	$ 26.97	$ 33.35	$ 252.69	$ 259.07	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ (2.83)	$ (2.37)	-13%	-11%
114	135	1,229	$ 225.72	$ 33.64	$ 40.01	$ 259.36	$ 265.73	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ (2.34)	$ (1.88)	-11%	-8%
136	158	1,350	$ 225.72	$ 40.31	$ 46.68	$ 266.03	$ 272.40	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ (1.86)	$ (1.39)	-8%	-6%
159	180	1,545	$ 225.72	$ 46.98	$ 53.35	$ 272.70	$ 279.07	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ (1.37)	$ (0.90)	-6%	-4%
181	203	1,663	$ 225.72	$ 53.65	$ 60.02	$ 279.37	$ 285.74	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ (0.88)	$ (0.41)	-4%	-2%
204	225	1,806	$ 225.72	$ 60.32	$ 66.69	$ 286.04	$ 292.41	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ (0.39)	$ 0.08	-2%	0%
226	248	1,965	$ 225.72	$ 66.99	$ 73.36	$ 292.71	$ 299.08	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 0.10	$ 0.57	0%	2%
249	270	1,976	$ 225.72	$ 73.66	$ 80.03	$ 299.38	$ 305.75	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 0.59	$ 1.05	2%	4%
271	293	2,013	$ 225.72	$ 80.32	$ 86.70	$ 306.04	$ 312.42	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 1.08	$ 1.54	4%	6%
294	315	2,080	$ 225.72	$ 86.99	$ 93.37	$ 312.71	$ 319.09	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 1.56	$ 2.03	6%	8%
316	338	1,911	$ 225.72	$ 93.66	$ 100.04	$ 319.38	$ 325.76	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 2.05	$ 2.52	8%	9%
339	360	1,835	$ 225.72	$ 100.33	$ 106.70	$ 326.05	$ 332.42	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 2.54	$ 3.01	9%	11%
361	468	7,278	$ 225.72	$ 107.00	$ 138.80	$ 332.72	$ 364.52	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 2.99	$ 1.28	11%	4%
469	577	4,181	$ 225.72	$ 139.10	$ 170.91	$ 364.82	$ 396.63	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.26	$ (0.46)	4%	-1%
578	685	2,250	$ 225.72	$ 171.20	$ 203.01	$ 396.92	$ 428.73	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (0.47)	$ (2.19)	-1%	-6%
686	793	1,222	$ 225.72	$ 203.30	$ 235.11	$ 429.02	$ 460.83	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (2.21)	$ (3.92)	-6%	-10%
794	902	593	$ 225.72	$ 235.40	$ 267.21	$ 461.12	$ 492.93	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (3.94)	$ (5.66)	-10%	-14%
903	1010	285	$ 225.72	$ 267.51	$ 299.31	$ 493.23	$ 525.03	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (5.67)	$ (7.39)	-14%	-17%
1,011	1118	188	$ 225.72	$ 299.61	$ 331.41	$ 525.33	$ 557.13	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (7.41)	$ (9.12)	-17%	-20%
1,119	1226	92	$ 225.72	$ 331.71	$ 363.51	$ 557.43	$ 589.23	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (9.14)	$ (10.86)	-20%	-22%
1,227	1335	60	$ 225.72	$ 363.81	$ 395.61	$ 589.53	$ 621.33	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (10.87)	$ (12.59)	-22%	-24%
1,336	1443	36	$ 225.72	$ 395.91	$ 427.71	$ 621.63	$ 653.43	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (12.61)	$ (14.32)	-24%	-26%
1,444	1551	21	$ 225.72	$ 428.01	$ 459.81	$ 653.73	$ 685.53	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (14.34)	$ (16.06)	-26%	-28%
1,552	1660	16	$ 225.72	$ 460.11	$ 491.92	$ 685.83	$ 717.64	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (16.07)	$ (17.79)	-28%	-30%
1,661	1768	11	$ 225.72	$ 492.21	$ 524.02	$ 717.93	$ 749.74	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (17.81)	$ (19.52)	-30%	-31%
1,769	1876	22	$ 225.72	$ 524.31	$ 556.12	$ 750.03	$ 781.84	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (19.54)	$ (21.26)	-31%	-33%
1,877	4151	41	$ 225.72	$ 556.41	$ 1,230.24	$ 782.13	$ 1,455.96	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (21.27)	$ (57.66)	-33%	-48%

A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADIONAL RATE STRUCTURE

Annual Residential Bill Impacts of CGSA A/B Rate Structure in GCSA Environs Compared to Traditional Rate Structure

								$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 18.81	$ 0.29640	$ 0.29640			$ 27.58	$ 0.10435	$ 0.10435	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	23	41	$ 225.72	$ -	$ 6.67	$ 225.72	$ 232.39	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ (4.81)	$ (4.32)	-26%	-22%
24	45	23	$ 225.72	$ 6.97	$ 13.34	$ 232.69	$ 239.06	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ (4.30)	$ (3.83)	-22%	-19%
46	68	28	$ 225.72	$ 13.63	$ 20.01	$ 239.35	$ 245.73	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ (3.81)	$ (3.34)	-19%	-16%
69	90	28	$ 225.72	$ 20.30	$ 26.68	$ 246.02	$ 252.40	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ (3.32)	$ (2.86)	-16%	-14%
91	113	32	$ 225.72	$ 26.97	$ 33.35	$ 252.69	$ 259.07	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ (2.83)	$ (2.37)	-13%	-11%
114	135	34	$ 225.72	$ 33.64	$ 40.01	$ 259.36	$ 265.73	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ (2.34)	$ (1.88)	-11%	-8%
136	158	37	$ 225.72	$ 40.31	$ 46.68	$ 266.03	$ 272.40	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ (1.86)	$ (1.39)	-8%	-6%
159	180	43	$ 225.72	$ 46.98	$ 53.35	$ 272.70	$ 279.07	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ (1.37)	$ (0.90)	-6%	-4%
181	203	46	$ 225.72	$ 53.65	$ 60.02	$ 279.37	$ 285.74	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ (0.88)	$ (0.41)	-4%	-2%
204	225	50	$ 225.72	$ 60.32	$ 66.69	$ 286.04	$ 292.41	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ (0.39)	$ 0.08	-2%	0%
226	248	55	$ 225.72	$ 66.99	$ 73.36	$ 292.71	$ 299.08	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 0.10	$ 0.57	0%	2%
249	270	55	$ 225.72	$ 73.66	$ 80.03	$ 299.38	$ 305.75	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 0.59	$ 1.05	2%	4%
271	293	56	$ 225.72	$ 80.32	$ 86.70	$ 306.04	$ 312.42	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 1.08	$ 1.54	4%	6%
294	315	58	$ 225.72	$ 86.99	$ 93.37	$ 312.71	$ 319.09	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 1.56	$ 2.03	6%	8%
316	338	53	$ 225.72	$ 93.66	$ 100.04	$ 319.38	$ 325.76	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 2.05	$ 2.52	8%	9%
339	360	51	$ 225.72	$ 100.33	$ 106.70	$ 326.05	$ 332.42	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 2.54	$ 3.01	9%	11%
361	468	202	$ 225.72	$ 107.00	$ 138.80	$ 332.72	$ 364.52	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 2.99	$ 1.28	11%	4%
469	577	116	$ 225.72	$ 139.10	$ 170.91	$ 364.82	$ 396.63	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.26	$ (0.46)	4%	-1%
578	685	62	$ 225.72	$ 171.20	$ 203.01	$ 396.92	$ 428.73	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (0.47)	$ (2.19)	-1%	-6%
686	793	34	$ 225.72	$ 203.30	$ 235.11	$ 429.02	$ 460.83	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (2.21)	$ (3.92)	-6%	-10%
794	902	16	$ 225.72	$ 235.40	$ 267.21	$ 461.12	$ 492.93	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (3.94)	$ (5.66)	-10%	-14%
903	1010	8	$ 225.72	$ 267.51	$ 299.31	$ 493.23	$ 525.03	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (5.67)	$ (7.39)	-14%	-17%
1,011	1118	5	$ 225.72	$ 299.61	$ 331.41	$ 525.33	$ 557.13	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (7.41)	$ (9.12)	-17%	-20%
1,119	1226	3	$ 225.72	$ 331.71	$ 363.51	$ 557.43	$ 589.23	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (9.14)	$ (10.86)	-20%	-22%
1,227	1335	2	$ 225.72	$ 363.81	$ 395.61	$ 589.53	$ 621.33	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (10.87)	$ (12.59)	-22%	-24%
1,336	1443	1	$ 225.72	$ 395.91	$ 427.71	$ 621.63	$ 653.43	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (12.61)	$ (14.32)	-24%	-26%
1,444	1551	1	$ 225.72	$ 428.01	$ 459.81	$ 653.73	$ 685.53	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (14.34)	$ (16.06)	-26%	-28%
1,552	1660	0	$ 225.72	$ 460.11	$ 491.92	$ 685.83	$ 717.64	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (16.07)	$ (17.79)	-28%	-30%
1,661	1768	0	$ 225.72	$ 492.21	$ 524.02	$ 717.93	$ 749.74	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (17.81)	$ (19.52)	-30%	-31%
1,769	1876	1	$ 225.72	$ 524.31	$ 556.12	$ 750.03	$ 781.84	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (19.54)	$ (21.26)	-31%	-33%
1,877	4151	1	$ 225.72	$ 556.41	$ 1,230.24	$ 782.13	$ 1,455.96	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (21.27)	$ (57.66)	-33%	-48%

A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADIONAL RATE STRUCTURE

Annual Residential Bill Impacts of CGSA A/B Rate Structure in City of Beaumont Compared to Traditional Rate Structure

								$ 14.00	$ 0.55702	$ 0.55702	Res A				
			$ 18.81	$ 0.29640	$ 0.29640			$ 27.58	$ 0.10435	$ 0.10435	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	23	-	$ 225.72	$ -	$ 6.67	$ 225.72	$ 232.39	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ (4.81)	$ (4.32)	-26%	-22%
24	45	-	$ 225.72	$ 6.97	$ 13.34	$ 232.69	$ 239.06	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ (4.30)	$ (3.83)	-22%	-19%
46	68	-	$ 225.72	$ 13.63	$ 20.01	$ 239.35	$ 245.73	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ (3.81)	$ (3.34)	-19%	-16%
69	90	-	$ 225.72	$ 20.30	$ 26.68	$ 246.02	$ 252.40	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ (3.32)	$ (2.86)	-16%	-14%
91	113	-	$ 225.72	$ 26.97	$ 33.35	$ 252.69	$ 259.07	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ (2.83)	$ (2.37)	-13%	-11%
114	135	-	$ 225.72	$ 33.64	$ 40.01	$ 259.36	$ 265.73	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ (2.34)	$ (1.88)	-11%	-8%
136	158	-	$ 225.72	$ 40.31	$ 46.68	$ 266.03	$ 272.40	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ (1.86)	$ (1.39)	-8%	-6%
159	180	-	$ 225.72	$ 46.98	$ 53.35	$ 272.70	$ 279.07	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ (1.37)	$ (0.90)	-6%	-4%
181	203	-	$ 225.72	$ 53.65	$ 60.02	$ 279.37	$ 285.74	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ (0.88)	$ (0.41)	-4%	-2%
204	225	-	$ 225.72	$ 60.32	$ 66.69	$ 286.04	$ 292.41	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ (0.39)	$ 0.08	-2%	0%
226	248	-	$ 225.72	$ 66.99	$ 73.36	$ 292.71	$ 299.08	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 0.10	$ 0.57	0%	2%
249	270	-	$ 225.72	$ 73.66	$ 80.03	$ 299.38	$ 305.75	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 0.59	$ 1.05	2%	4%
271	293	-	$ 225.72	$ 80.32	$ 86.70	$ 306.04	$ 312.42	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 1.08	$ 1.54	4%	6%
294	315	-	$ 225.72	$ 86.99	$ 93.37	$ 312.71	$ 319.09	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 1.56	$ 2.03	6%	8%
316	338	1	$ 225.72	$ 93.66	$ 100.04	$ 319.38	$ 325.76	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 2.05	$ 2.52	8%	9%
339	360	-	$ 225.72	$ 100.33	$ 106.70	$ 326.05	$ 332.42	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 2.54	$ 3.01	9%	11%
361	468	-	$ 225.72	$ 107.00	$ 138.80	$ 332.72	$ 364.52	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 2.99	$ 1.28	11%	4%
469	577	-	$ 225.72	$ 139.10	$ 170.91	$ 364.82	$ 396.63	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.26	$ (0.46)	4%	-1%
578	685	-	$ 225.72	$ 171.20	$ 203.01	$ 396.92	$ 428.73	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (0.47)	$ (2.19)	-1%	-6%
686	793	-	$ 225.72	$ 203.30	$ 235.11	$ 429.02	$ 460.83	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (2.21)	$ (3.92)	-6%	-10%
794	902	-	$ 225.72	$ 235.40	$ 267.21	$ 461.12	$ 492.93	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (3.94)	$ (5.66)	-10%	-14%
903	1010	-	$ 225.72	$ 267.51	$ 299.31	$ 493.23	$ 525.03	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (5.67)	$ (7.39)	-14%	-17%
1,011	1118	-	$ 225.72	$ 299.61	$ 331.41	$ 525.33	$ 557.13	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (7.41)	$ (9.12)	-17%	-20%
1,119	1226	-	$ 225.72	$ 331.71	$ 363.51	$ 557.43	$ 589.23	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (9.14)	$ (10.86)	-20%	-22%
1,227	1335	-	$ 225.72	$ 363.81	$ 395.61	$ 589.53	$ 621.33	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (10.87)	$ (12.59)	-22%	-24%
1,336	1443	-	$ 225.72	$ 395.91	$ 427.71	$ 621.63	$ 653.43	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (12.61)	$ (14.32)	-24%	-26%
1,444	1551	-	$ 225.72	$ 428.01	$ 459.81	$ 653.73	$ 685.53	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (14.34)	$ (16.06)	-26%	-28%
1,552	1660	-	$ 225.72	$ 460.11	$ 491.92	$ 685.83	$ 717.64	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (16.07)	$ (17.79)	-28%	-30%
1,661	1768	-	$ 225.72	$ 492.21	$ 524.02	$ 717.93	$ 749.74	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (17.81)	$ (19.52)	-30%	-31%
1,769	1876	-	$ 225.72	$ 524.31	$ 556.12	$ 750.03	$ 781.84	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (19.54)	$ (21.26)	-31%	-33%
1,877	4151	-	$ 225.72	$ 556.41	$ 1,230.24	$ 782.13	$ 1,455.96	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (21.27)	$ (57.66)	-33%	-48%

CURRENT AND RECOMMENDED RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CURRENT AND RECOMMENDED RATES

Description		Current Rates CTSA Incorporated and Environs Rates	Recommended	
(a)		(b)	(c) Rate Option A	(d) Rate Option B
Residential				
Customer Charge		$18.81	$14.00	$27.61
Usage Rates	All Ccf	$0.12061	$0.55346	$0.09979
Commercial				
Customer Charge - Sales		$53.33	$53.33	
Usage Rates	All Ccf	$0.11614	$0.11615	
	First 250			
	All Over 250			
Customer Charge - Transportation		$265.33	$265.33	
Usage Rates	All Ccf	$0.11614	$0.11615	
	First 250			
	All Over 250			
Industrial				
Customer Charge - Sales		$320.96	$320.96	
Usage Rates	All Ccf	$0.10273	$0.10276	
	First 250			
	All Over 250			
Customer Charge - Transportation		$520.96	$520.96	
Usage Rates	All Ccf	$0.10273	$0.10276	
	First 250			
	All Over 250			
Public Authority				
Customer Charge - Sales		$81.70	$81.70	
Usage Rates	All Ccf	$0.11541	$0.11579	
	First 250			
	All Over 250			
Customer Charge - Transportation		$104.70	$104.70	
Usage Rates	All Ccf	$0.11541	$0.11579	
	First 250			
	All Over 250			
Cogeneration				
Customer Charge - Sales		$104.70	$104.70	
Usage Rates	First 5,000 Ccf	$0.07720	$0.07720	
	Next 35,000	$0.06850	$0.06850	
	Next 60,000	$0.05524	$0.05524	
	All Over 100,000	$0.04016	$0.04016	
Customer Charge - Transportation		$104.70	$104.70	
Usage Rates	First 5,000 Ccf	$0.07720	$0.07720	
	Next 35,000	$0.06850	$0.06850	
	Next 60,000	$0.05524	$0.05524	
	All Over 100, 000	$0.04016	$0.04016	
Public Schools Space Heating				
Customer Charge - Sales		$134.70	$134.70	
Usage Rates	All Ccf	$0.10012	$0.10012	
Customer Charge - Transportation		$234.70	$234.70	
Usage Rates	All Ccf	$0.10012	$0.10012	
Compressed Natural Gas				
Customer Charge - Sales		$192.63	$192.63	
	All Ccf	$0.06684	$0.06684	
Customer Charge - Transportation		$217.63	$217.63	
	All Ccf	$0.06684	$0.06684	

PROOF OF REVENUE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROOF OF REVENUE

					Recommended Rates					
Line	Description	Bills	Volumes		Customer Charge	Usage Charges	Calculated Revenue at Recommended Rates		Assigned Revenue	Rounding Diff.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Residential - Rate Option A	1,654,162			$ 14.00		$ 23,158,262			
2			All Ccf	30,159,573		0.55346	$ 16,692,117			
3	Residential - Rate Option B	1,365,889			$ 27.61		$ 37,712,193			
4			All Ccf	61,261,014		0.09979	$ 6,113,237			
5	Residential Total							$ 83,675,809	$ 83,676,165	$ (355)
6										
7	Commercial	147,701			$ 53.33		$ 7,876,902			
8			All Ccf	38,835,224		0.11615	$ 4,510,711	$ 12,387,613		
9										
10	Commercial Transportation	4,029			$ 265.33		$ 1,069,050			
11			All Ccf	17,413,058		0.11615	$ 2,022,527	$ 3,091,577		
12										
13	Commercial Total							$ 15,479,190	$ 15,479,042	$ 148
14										
15	Industrial	256			$ 320.96		$ 82,137			
16			All Ccf	656,316		0.10276	$ 67,443	$ 149,580		
17										
18	Industrial Transportation	396			$ 520.96		$ 206,300			
19			All Ccf	5,831,603		0.10276	$ 599,255	$ 805,556		
20										
21	Industrial Total							$ 955,135	$ 955,148	$ (13)
22										
23	Public Authority	6,797			$ 81.70		$ 555,318			
24			All Ccf	2,849,065		0.11579	$ 329,893	$ 885,211		
25										
26	Public Authority Transportation	4,681			$ 104.70		$ 490,101			
27			All Ccf	7,397,100		0.11579	$ 856,510	$ 1,346,611		
28										
29										

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PROOF OF REVENUE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROOF OF REVENUE

Line	Description	Bills	Volumes		Recommended Rates Customer Charge	Recommended Rates Usage Charges	Calculated Revenue at Recommended Rates		Assigned Revenue	Rounding Diff.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
30	COGEN Transportation	12			$ 104.70		$ 1,256			
31										
32			First 5000	60,000		0.07720	$ 4,632			
33			Next 35,000	420,000		0.06850	$ 28,770			
34			Next 60,000	720,000		0.05524	$ 39,773			
35			Over 100,000	2,685,983		0.04016	$ 107,869	$ 182,300		
36										
37	Public Schools Space Heating	65			$ 134.70		$ 8,709			
38			All Ccf	124,603		0.10012	12475.27645	$ 21,185		
39										
40	Public Schools Space Heating Transportation	980			$ 234.70		$ 230,006			
41			All Ccf	1,200,155		0.10012	$ 120,159	$ 350,165		
42										
43	Public Authority Total							$ 2,785,473	$ 2,785,489	$ (16)
44										
45	Compressed Nat. Gas	36			$ 192.63		$ 6,935			
46			All Ccf	620		0.06684	$ 41	$ 6,976		
47	Compressed Nat. Gas Transportation	48			$ 217.63		$ 10,446			
48			All Ccf	1,352,087		0.06684	$ 90,373	$ 100,820		
49	Compressed Nat. Gas Total							$ 107,796	$ 107,796	$ (0)
50										
51	Total Revenue - All Classes									
52	Recommended Rate Revenue							$ 103,003,403	$ 103,003,640	
53	Current Rate Revenue							$ 87,161,240	$ 87,161,240	
54	Revenue Change							$ 15,842,163	$ 15,842,399	$ (236)
55	Schedule A - Revenue Deficiency								$ 15,842,399	

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CUSTOMER BILL IMPACTS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CUSTOMER BILL IMPACTS

	Year-Round Average Bill				Average January Bill			
			Change				Change	
Description	Current	Recommended	Dollars	%	Current	Recommended	$	%
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Sales Service: (1) (2)								
Residential - Rate Option A								
CTSA Incorporated	$ 29.33	$ 32.42	$ 3.09	10.5%	$ 47.41	$ 64.05	$ 16.64	35.1%
CTSA Environs	$ 29.33	$ 32.42	$ 3.09	10.5%	$ 47.41	$ 64.05	$ 16.64	35.1%
Residential - Rate Option B								
CTSA Incorporated	$ 44.70	$ 52.56	$ 7.86	17.6%	$ 89.17	$ 95.43	$ 6.26	7.0%
CTSA Environs	$ 44.70	$ 52.56	$ 7.86	17.6%	$ 89.17	$ 95.43	$ 6.26	7.0%
Commercial								
CTSA Incorporated	$ 203.92	$ 203.92	$ -	0.0%	$ 311.45	$ 311.45	$ -	0.0%
CTSA Environs	$ 203.92	$ 203.92	$ -	0.0%	$ 311.45	$ 311.45	$ -	0.0%
Industrial								
CTSA Incorporated and Environs	$ 1,755.39	$ 1,755.47	$ 0.08	0.0%	$ 3,245.01	$ 3,245.17	$ 0.16	0.0%
Public Authority								
CTSA Incorporated and Environs	$ 321.46	$ 321.62	$ 0.16	0.0%	$ 612.85	$ 613.20	$ 0.35	0.1%
Public Schools Space Heating								
CTSA Incorporated and Environs	$ 1,207.53	$ 1,207.53	$ -	0.0%	$ 1,412.18	$ 1,412.18	$ -	0.0%
Compressed Natural Gas								
CTSA Incorporated	$ 201.64	$ 201.64	$ -	0.0%	$ 208.34	$ 208.34	$ -	0.0%

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CUSTOMER BILL IMPACTS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CUSTOMER BILL IMPACTS

	Year-Round Average Bill				Average January Bill			
			Change				Change	
Description	Current	Recommended	Dollars	%	Current	Recommended	$	%
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Transportation Service: (3)								
Commercial Transportation								
CTSA Incorporated	$ 2,641.85	$ 2,641.89	$ 0.04	0.0%	$ 3,099.27	$ 3,099.33	$ 0.06	0.0%
CTSA Environs	$ 2,641.85	$ 2,641.89	$ 0.04	0.0%	$ 3,099.27	$ 3,099.33	$ 0.06	0.0%
Industrial Transportation								
CTSA Incorporated and Environs	$ 8,421.34	$ 8,221.78	$ (199.56)	-2.4%	$ 9,514.66	$ 9,315.17	$ (199.49)	-2.1%
Public Authority Transportation								
CTSA Incorporated and Environs	$ 972.51	$ 973.11	$ 0.60	0.1%	$ 1,382.92	$ 1,383.80	$ 0.88	0.1%
Public School Space Heating Transportation								
CTSA Incorporated and Environs	$ 888.51	$ 888.51	$ -	0.0%	$ 1,404.61	$ 1,404.61	$ -	0.0%
Cogeneration Transportation (4)								
CTSA Incorporated	$ 155,654.46	$ 155,654.46	$ -	0.0%	$ 163,214.82	$ 163,214.82	$ -	0.0%
Compressed Natural Gas Transportation								
CTSA Incorporated and Environs	$ 14,318.55	$ 14,318.55	$ -	0.0%	$ 13,331.27	$ 13,331.27	$ -	0.0%

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CUSTOMER BILL IMPACTS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CUSTOMER BILL IMPACTS

	Year-Round Average Bill				Average January Bill			
			Change				Change	
Description	Current	Recommended	Dollars	%	Current	Recommended	$	%
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)

(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:

	CGSA	
	Year-Round	January
Residential - Rate Option A	18	50
Residential - Rate Option B	45	122
Commercial	263	451
Industrial	2,565	5,228
Public Authority	419	929
Public School Space Heating	1,927	2,295
Compressed Natural Gas	17	30

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

	CGSA	
	Year-Round	January
Commercial Transportation	4,322	5,154
Industrial Transportation	14,726	16,764
Public Authority Transportation	1,580	2,328
Public School Space Heating Transportation	1,225	2,191
Compressed Natural Gas Transportation	28,168	26,196
	August	January
Cogeneration Transportation	339,785	323,832

(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.

A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of CTSA A/B Rate Relative to Existing CTSA Rates

								$ 14.00	$ 0.55346	$ 0.55346	Res A					
			$ 18.81	$ 0.12061	$ 0.12061			$ 27.61	$ 0.09979	$ 0.09979	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	23	2,085	$ 225.72	$ -	$ 2.71	$ 225.72	$ 228.43	$ 168.00	$ -	$ 12.45	$ 168.00	$ 180.45	$ (4.81)	$ (4.00)	-26%	-21%
24	45	2,006	$ 225.72	$ 2.83	$ 5.43	$ 228.55	$ 231.15	$ 168.00	$ 13.01	$ 24.91	$ 181.01	$ 192.91	$ (3.96)	$ (3.19)	-21%	-17%
46	68	2,578	$ 225.72	$ 5.55	$ 8.14	$ 231.27	$ 233.86	$ 168.00	$ 25.46	$ 37.36	$ 193.46	$ 205.36	$ (3.15)	$ (2.38)	-16%	-12%
69	90	3,693	$ 225.72	$ 8.26	$ 10.85	$ 233.98	$ 236.57	$ 168.00	$ 37.91	$ 49.81	$ 205.91	$ 217.81	$ (2.34)	$ (1.56)	-12%	-8%
91	113	4,722	$ 225.72	$ 10.98	$ 13.57	$ 236.70	$ 239.29	$ 168.00	$ 50.36	$ 62.26	$ 218.36	$ 230.26	$ (1.53)	$ (0.75)	-8%	-4%
114	135	6,110	$ 225.72	$ 13.69	$ 16.28	$ 239.41	$ 242.00	$ 168.00	$ 62.82	$ 74.72	$ 230.82	$ 242.72	$ (0.72)	$ 0.06	-4%	0%
136	158	7,285	$ 225.72	$ 16.40	$ 19.00	$ 242.12	$ 244.72	$ 168.00	$ 75.27	$ 87.17	$ 243.27	$ 255.17	$ 0.10	$ 0.87	0%	4%
159	180	8,522	$ 225.72	$ 19.12	$ 21.71	$ 244.84	$ 247.43	$ 168.00	$ 87.72	$ 99.62	$ 255.72	$ 267.62	$ 0.91	$ 1.68	4%	8%
181	203	10,021	$ 225.72	$ 21.83	$ 24.42	$ 247.55	$ 250.14	$ 168.00	$ 100.18	$ 112.08	$ 268.18	$ 280.08	$ 1.72	$ 2.49	8%	12%
204	225	11,477	$ 225.72	$ 24.54	$ 27.14	$ 250.26	$ 252.86	$ 168.00	$ 112.63	$ 124.53	$ 280.63	$ 292.53	$ 2.53	$ 3.31	12%	16%
226	248	12,263	$ 225.72	$ 27.26	$ 29.85	$ 252.98	$ 255.57	$ 168.00	$ 125.08	$ 136.98	$ 293.08	$ 304.98	$ 3.34	$ 4.12	16%	19%
249	270	13,208	$ 225.72	$ 29.97	$ 32.56	$ 255.69	$ 258.28	$ 168.00	$ 137.53	$ 149.43	$ 305.53	$ 317.43	$ 4.15	$ 4.93	19%	23%
271	293	13,691	$ 225.72	$ 32.69	$ 35.28	$ 258.41	$ 261.00	$ 168.00	$ 149.99	$ 161.89	$ 317.99	$ 329.89	$ 4.97	$ 5.74	23%	26%
294	315	13,818	$ 225.72	$ 35.40	$ 37.99	$ 261.12	$ 263.71	$ 168.00	$ 162.44	$ 174.34	$ 330.44	$ 342.34	$ 5.78	$ 6.55	27%	30%
316	338	13,485	$ 225.72	$ 38.11	$ 40.71	$ 263.83	$ 266.43	$ 168.00	$ 174.89	$ 186.79	$ 342.89	$ 354.79	$ 6.59	$ 7.36	30%	33%
339	360	12,886	$ 225.72	$ 40.83	$ 43.42	$ 266.55	$ 269.14	$ 168.00	$ 187.35	$ 199.25	$ 355.35	$ 367.25	$ 7.40	$ 8.18	33%	36%
361	586	78,801	$ 225.72	$ 43.54	$ 70.65	$ 269.26	$ 296.37	$ 331.32	$ 199.80	$ 58.45	$ 531.12	$ 389.77	$ 21.82	$ 7.78	97%	32%
587	812	23,302	$ 225.72	$ 70.77	$ 97.88	$ 296.49	$ 323.60	$ 331.32	$ 324.75	$ 80.98	$ 656.07	$ 412.30	$ 29.96	$ 7.39	121%	27%
813	1,037	6,767	$ 225.72	$ 98.00	$ 125.11	$ 323.72	$ 350.83	$ 331.32	$ 449.70	$ 103.51	$ 781.02	$ 434.83	$ 38.11	$ 7.00	141%	24%
1,038	1,263	2,333	$ 225.72	$ 125.23	$ 152.34	$ 350.95	$ 378.06	$ 331.32	$ 574.65	$ 126.04	$ 905.97	$ 457.36	$ 46.25	$ 6.61	158%	21%
1,264	1,489	1,062	$ 225.72	$ 152.46	$ 179.57	$ 378.18	$ 405.29	$ 331.32	$ 699.60	$ 148.57	$ 1,030.92	$ 479.89	$ 54.40	$ 6.22	173%	18%
1,490	1,715	585	$ 225.72	$ 179.69	$ 206.79	$ 405.41	$ 432.51	$ 331.32	$ 824.55	$ 171.10	$ 1,155.87	$ 502.42	$ 62.54	$ 5.83	185%	16%
1,716	1,940	316	$ 225.72	$ 206.92	$ 234.02	$ 432.64	$ 459.74	$ 331.32	$ 949.50	$ 193.63	$ 1,280.82	$ 524.95	$ 70.68	$ 5.43	196%	14%
1,941	2,166	185	$ 225.72	$ 234.14	$ 261.25	$ 459.86	$ 486.97	$ 331.32	$ 1,074.45	$ 216.15	$ 1,405.77	$ 547.47	$ 78.83	$ 5.04	206%	12%
2,167	2,392	122	$ 225.72	$ 261.37	$ 288.48	$ 487.09	$ 514.20	$ 331.32	$ 1,199.40	$ 238.68	$ 1,530.72	$ 570.00	$ 86.97	$ 4.65	214%	11%
2,393	2,618	101	$ 225.72	$ 288.60	$ 315.71	$ 514.32	$ 541.43	$ 331.32	$ 1,324.35	$ 261.21	$ 1,655.67	$ 592.53	$ 95.11	$ 4.26	222%	9%
2,619	2,843	69	$ 225.72	$ 315.83	$ 342.94	$ 541.55	$ 568.66	$ 331.32	$ 1,449.30	$ 283.74	$ 1,780.62	$ 615.06	$ 103.26	$ 3.87	229%	8%
2,844	3,069	41	$ 225.72	$ 343.06	$ 370.17	$ 568.78	$ 595.89	$ 331.32	$ 1,574.25	$ 306.27	$ 1,905.57	$ 637.59	$ 111.40	$ 3.48	235%	7%
3,070	3,295	45	$ 225.72	$ 370.29	$ 397.40	$ 596.01	$ 623.12	$ 331.32	$ 1,699.20	$ 328.80	$ 2,030.52	$ 660.12	$ 119.54	$ 3.08	241%	6%
3,296	3,521	22	$ 225.72	$ 397.52	$ 424.63	$ 623.24	$ 650.35	$ 331.32	$ 1,824.15	$ 351.33	$ 2,155.47	$ 682.65	$ 127.69	$ 2.69	246%	5%
3,522	8,262	70	$ 225.72	$ 424.75	$ 996.44	$ 650.47	$ 1,222.16	$ 331.32	$ 1,949.10	$ 824.43	$ 2,280.42	$ 1,155.75	$ 135.83	$ (5.53)	251%	-5%

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A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL TEXAS SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADITIONAL RATE STRUCTURE

Annual Residential Bill Impacts of CTSA A/B Rate Structure Compared to Traditional Rate Structure

								$ 14.00	$ 0.55346	$ 0.55346	Res A					
			$ 18.81	$ 0.29391	$ 0.29391			$ 27.61	$ 0.09979	$ 0.09979	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	23	2,085	$ 225.72	$ -	$ 6.61	$ 225.72	$ 232.33	$ 168.00	$ -	$ 12.45	$ 168.00	$ 180.45	$ (4.81)	$ (4.32)	-26%	-22%
24	45	2,006	$ 225.72	$ 6.91	$ 13.23	$ 232.63	$ 238.95	$ 168.00	$ 13.01	$ 24.91	$ 181.01	$ 192.91	$ (4.30)	$ (3.84)	-22%	-19%
46	68	2,578	$ 225.72	$ 13.52	$ 19.84	$ 239.24	$ 245.56	$ 168.00	$ 25.46	$ 37.36	$ 193.46	$ 205.36	$ (3.82)	$ (3.35)	-19%	-16%
69	90	3,693	$ 225.72	$ 20.13	$ 26.45	$ 245.85	$ 252.17	$ 168.00	$ 37.91	$ 49.81	$ 205.91	$ 217.81	$ (3.33)	$ (2.86)	-16%	-14%
91	113	4,722	$ 225.72	$ 26.75	$ 33.06	$ 252.47	$ 258.78	$ 168.00	$ 50.36	$ 62.26	$ 218.36	$ 230.26	$ (2.84)	$ (2.38)	-14%	-11%
114	135	6,110	$ 225.72	$ 33.36	$ 39.68	$ 259.08	$ 265.40	$ 168.00	$ 62.82	$ 74.72	$ 230.82	$ 242.72	$ (2.36)	$ (1.89)	-11%	-9%
136	158	7,285	$ 225.72	$ 39.97	$ 46.29	$ 265.69	$ 272.01	$ 168.00	$ 75.27	$ 87.17	$ 243.27	$ 255.17	$ (1.87)	$ (1.40)	-8%	-6%
159	180	8,522	$ 225.72	$ 46.58	$ 52.90	$ 272.30	$ 278.62	$ 168.00	$ 87.72	$ 99.62	$ 255.72	$ 267.62	$ (1.38)	$ (0.92)	-6%	-4%
181	203	10,021	$ 225.72	$ 53.20	$ 59.52	$ 278.92	$ 285.24	$ 168.00	$ 100.18	$ 112.08	$ 268.18	$ 280.08	$ (0.90)	$ (0.43)	-4%	-2%
204	225	11,477	$ 225.72	$ 59.81	$ 66.13	$ 285.53	$ 291.85	$ 168.00	$ 112.63	$ 124.53	$ 280.63	$ 292.53	$ (0.41)	$ 0.06	-2%	0%
226	248	12,263	$ 225.72	$ 66.42	$ 72.74	$ 292.14	$ 298.46	$ 168.00	$ 125.08	$ 136.98	$ 293.08	$ 304.98	$ 0.08	$ 0.54	0%	2%
249	270	13,208	$ 225.72	$ 73.04	$ 79.36	$ 298.76	$ 305.08	$ 168.00	$ 137.53	$ 149.43	$ 305.53	$ 317.43	$ 0.56	$ 1.03	2%	4%
271	293	13,691	$ 225.72	$ 79.65	$ 85.97	$ 305.37	$ 311.69	$ 168.00	$ 149.99	$ 161.89	$ 317.99	$ 329.89	$ 1.05	$ 1.52	4%	6%
294	315	13,818	$ 225.72	$ 86.26	$ 92.58	$ 311.98	$ 318.30	$ 168.00	$ 162.44	$ 174.34	$ 330.44	$ 342.34	$ 1.54	$ 2.00	6%	8%
316	338	13,485	$ 225.72	$ 92.88	$ 99.19	$ 318.60	$ 324.91	$ 168.00	$ 174.89	$ 186.79	$ 342.89	$ 354.79	$ 2.02	$ 2.49	8%	9%
339	360	12,886	$ 225.72	$ 99.49	$ 105.81	$ 325.21	$ 331.53	$ 168.00	$ 187.35	$ 199.25	$ 355.35	$ 367.25	$ 2.51	$ 2.98	9%	11%
361	586	78,801	$ 225.72	$ 106.10	$ 172.16	$ 331.82	$ 397.88	$ 331.32	$ 199.80	$ 58.45	$ 531.12	$ 389.77	$ 16.61	$ (0.68)	60%	-2%
587	812	23,302	$ 225.72	$ 172.46	$ 238.52	$ 398.18	$ 464.24	$ 331.32	$ 324.75	$ 80.98	$ 656.07	$ 412.30	$ 21.49	$ (4.33)	65%	-11%
813	1,037	6,767	$ 225.72	$ 238.81	$ 304.87	$ 464.53	$ 530.59	$ 331.32	$ 449.70	$ 103.51	$ 781.02	$ 434.83	$ 26.37	$ (7.98)	68%	-18%
1,038	1,263	2,333	$ 225.72	$ 305.16	$ 371.22	$ 530.88	$ 596.94	$ 331.32	$ 574.65	$ 126.04	$ 905.97	$ 457.36	$ 31.26	$ (11.63)	71%	-23%
1,264	1,489	1,062	$ 225.72	$ 371.52	$ 437.58	$ 597.24	$ 663.30	$ 331.32	$ 699.60	$ 148.57	$ 1,030.92	$ 479.89	$ 36.14	$ (15.28)	73%	-28%
1,490	1,715	585	$ 225.72	$ 437.87	$ 503.93	$ 663.59	$ 729.65	$ 331.32	$ 824.55	$ 171.10	$ 1,155.87	$ 502.42	$ 41.02	$ (18.94)	74%	-31%
1,716	1,940	316	$ 225.72	$ 504.22	$ 570.28	$ 729.94	$ 796.00	$ 331.32	$ 949.50	$ 193.63	$ 1,280.82	$ 524.95	$ 45.91	$ (22.59)	75%	-34%
1,941	2,166	185	$ 225.72	$ 570.58	$ 636.64	$ 796.30	$ 862.36	$ 331.32	$ 1,074.45	$ 216.15	$ 1,405.77	$ 547.47	$ 50.79	$ (26.24)	77%	-37%
2,167	2,392	122	$ 225.72	$ 636.93	$ 702.99	$ 862.65	$ 928.71	$ 331.32	$ 1,199.40	$ 238.68	$ 1,530.72	$ 570.00	$ 55.67	$ (29.89)	77%	-39%
2,393	2,618	101	$ 225.72	$ 703.28	$ 769.34	$ 929.00	$ 995.06	$ 331.32	$ 1,324.35	$ 261.21	$ 1,655.67	$ 592.53	$ 60.56	$ (33.54)	78%	-40%
2,619	2,843	69	$ 225.72	$ 769.64	$ 835.70	$ 995.36	$ 1,061.42	$ 331.32	$ 1,449.30	$ 283.74	$ 1,780.62	$ 615.06	$ 65.44	$ (37.20)	79%	-42%
2,844	3,069	41	$ 225.72	$ 835.99	$ 902.05	$ 1,061.71	$ 1,127.77	$ 331.32	$ 1,574.25	$ 306.27	$ 1,905.57	$ 637.59	$ 70.32	$ (40.85)	79%	-43%
3,070	3,295	45	$ 225.72	$ 902.35	$ 968.41	$ 1,128.07	$ 1,194.13	$ 331.32	$ 1,699.20	$ 328.80	$ 2,030.52	$ 660.12	$ 75.20	$ (44.50)	80%	-45%
3,296	3,521	22	$ 225.72	$ 968.70	$ 1,034.76	$ 1,194.42	$ 1,260.48	$ 331.32	$ 1,824.15	$ 351.33	$ 2,155.47	$ 682.65	$ 80.09	$ (48.15)	80%	-46%
3,522	8,262	70	$ 225.72	$ 1,035.05	$ 2,428.19	$ 1,260.77	$ 2,653.91	$ 331.32	$ 1,949.10	$ 824.43	$ 2,280.42	$ 1,155.75	$ 84.97	$ (124.85)	81%	-56%

Exhibit PHR-11
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CURRENT AND RECOMMENDED RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

CURRENT AND RECOMMENDED RATES

		Current Rates				
Description		GCSA Incorporated Rates	GCSA Environs Rates	City of Beaumont Rates	Recommended	
(a)		(b)	(c)	(d)	(e)	(f)
Residential					Rate Option A	Rate Option B
Customer Charge		$12.42	$14.17	$12.10	$14.00	$27.40
Usage Rates	All Ccf	$0.45616	$0.40680	$0.45616	$0.57854	$0.13187
Commercial						
Customer Charge - Sales		$51.11	$59.92	$49.49	$53.33	
Usage Rates	All Ccf				$0.19726	
	First 250	$0.22140	$0.20185	$0.22140		
	All Over 250	$0.19380	$0.17425	$0.19380		
Customer Charge - Transportation		$297.11	$305.92		$265.33	
Usage Rates	All Ccf				$0.19726	
	First 250	0.22140	0.20185			
	All Over 250	0.19380	0.17425			
Industrial						
Customer Charge - Transportation		$249.73	$432.79		$520.96	
Usage Rates	All Ccf				$0.35630	
	First 250	$0.40060	$0.37808			
	All Over 250	$0.37480	$0.35228			
Public Authority						
Customer Charge - Sales		$106.10	$117.78		$116.63	
Usage Rates	All Ccf				$0.11831	
	First 250	$0.15672	$0.13587			
	All Over 250	$0.13092	$0.11007			

Exhibit PHR-12
Page 1 of 1

PROOF OF REVENUE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

PROOF OF REVENUE

Line	Description	Bills	Volumes		Recommended Rates Customer Charge	Recommended Rates Usage Charges	Calculated Revenue at Recommended Rates		Assigned Revenue	Rounding Diff.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Residential - Rate Option A	306,959			$ 14.00		$ 4,297,422			
2			All Ccf	5,146,591		0.57854	$ 2,977,509			
3	Residential - Rate Option B	200,960			$ 27.40		$ 5,506,291			
4			All Ccf	9,031,418		0.13187	$ 1,190,973			
5	Residential Total							$ 13,972,195	$ 13,972,210	$ (16)
6										
7	Commercial	21,739			$ 53.33		$ 1,159,329			
8			All Ccf	5,658,396		0.19726	$ 1,116,175	$ 2,275,504		
9										
10	Commercial Transportation	356			$ 265.33		$ 94,457			
11			All Ccf	2,827,669		0.19726	$ 557,786	$ 652,243		
12										
13	Commercial Total							$ 2,927,747	$ 2,927,782	$ (35)
14										
15	Industrial Transportation	48			$ 520.96		$ 25,006			
16			All Ccf	686,830		0.35630	$ 244,718			
17	Industrial Transportation Total							$ 269,724	$ 269,721	$ 3
18										
19	Public Authority	3,174			$ 116.63		$ 370,170			
20			All Ccf	1,560,118		0.11831	$ 184,578			
21	Public Authority Total							$ 554,748	$ 554,740	8
22										
23	Total Revenue - All Classes									
24	Recommended Rate Revenue							$ 17,724,413	$ 17,724,453	
25	Current Rate Revenue							$ 16,532,474	$ 16,532,474	
26	Revenue Change							$ 1,191,939	$ 1,191,979	$ (40)
27	Schedule A - Revenue Deficiency								$ 1,191,979	

CUSTOMER BILL IMPACTS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

CUSTOMER BILL IMPACTS

	Year-Round Average Bill				Average January Bill			
			Change				Change	
Description	Current	Recommended	Dollars	%	Current	Recommended	$	%
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Sales Service: (1) (2)								
Residential - Rate Option A								
GCSA Incorporated	$ 28.40	$ 32.04	$ 3.64	12.8%	$ 52.47	$ 59.19	$ 6.72	12.8%
GCSA Environs	$ 29.33	$ 32.04	$ 2.71	9.2%	$ 52.15	$ 59.19	$ 7.04	13.5%
City of Beaumont	$ 28.08	$ 32.04	$ 3.96	14.1%	$ 52.15	$ 59.19	$ 7.04	13.5%
Residential - Rate Option B								
GCSA Incorporated	$ 55.27	$ 55.67	$ 0.40	0.7%	$ 119.77	$ 98.23	$ (21.54)	-18.0%
GCSA Environs	$ 54.80	$ 55.67	$ 0.87	1.6%	$ 115.96	$ 98.23	$ (17.73)	-15.3%
GCSA Environs	$ 54.95	$ 55.67	$ 0.72	1.3%	$ 119.45	$ 98.23	$ (21.22)	-17.8%
Commercial								
GCSA Incorporated	$ 237.88	$ 234.10	$ (3.78)	-1.6%	$ 317.93	$ 314.55	$ (3.38)	-1.1%
GCSA Environs	$ 241.60	$ 234.10	$ (7.50)	-3.1%	$ 319.38	$ 314.55	$ (4.83)	-1.5%
GCSA Environs	$ 236.26	$ 234.10	$ (2.16)	-0.9%	$ 316.31	$ 314.55	$ (1.76)	-0.6%
Public Authority								
GCSA Incorporated	$ 421.31	$ 419.19	$ (2.12)	-0.5%	$ 841.36	$ 830.81	$ (10.55)	-1.3%
GCSA Environs	$ 422.74	$ 419.19	$ (3.55)	-0.8%	$ 828.85	$ 830.81	$ 1.96	0.2%
Transportation Service: (3)								
Commercial Transportation								
GCSA Incorporated	$ 5,595.22	$ 5,584.03	$ (11.19)	-0.2%	$ 8,464.35	$ 8,468.05	$ 3.70	0.0%
Industrial Transportation								
GCSA Incorporated	$ 12,378.12	$ 12,378.18	$ 0.06	0.0%	$ 12,942.36	$ 12,930.10	$ (12.26)	-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
(2) Bills are based on the following average usage levels:

	GCSA	
	Year-Round	January
Residential	17	42
Commercial	260	376
Public Authority	492	1,160

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

	GCSA	
	Year-Round	January
Commercial Transportation	7,943	12,250
Industrial Transportation	14,309	14,975

A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of GCSA A/B Rate Relative to Existing GCSA Incorporated Rates

								$ 14.00	$ 0.57854	$ 0.57854	Res A					
			$ 12.42	$ 0.45616	$ 0.45616			$ 27.40	$ 0.13187	$ 0.13187	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	23	1,478	$ 149.04	$ -	$ 10.26	$ 149.04	$ 159.30	$ 168.00	$ -	$ 13.02	$ 168.00	$ 181.02	$ 1.58	$ 1.81	13%	14%
24	45	844	$ 149.04	$ 10.72	$ 20.53	$ 159.76	$ 169.57	$ 168.00	$ 13.60	$ 26.03	$ 181.60	$ 194.03	$ 1.82	$ 2.04	14%	14%
46	68	1,024	$ 149.04	$ 20.98	$ 30.79	$ 170.02	$ 179.83	$ 168.00	$ 26.61	$ 39.05	$ 194.61	$ 207.05	$ 2.05	$ 2.27	14%	15%
69	90	1,014	$ 149.04	$ 31.25	$ 41.05	$ 180.29	$ 190.09	$ 168.00	$ 39.63	$ 52.07	$ 207.63	$ 220.07	$ 2.28	$ 2.50	15%	16%
91	113	1,154	$ 149.04	$ 41.51	$ 51.32	$ 190.55	$ 200.36	$ 168.00	$ 52.65	$ 65.09	$ 220.65	$ 233.09	$ 2.51	$ 2.73	16%	16%
114	135	1,229	$ 149.04	$ 51.77	$ 61.58	$ 200.81	$ 210.62	$ 168.00	$ 65.66	$ 78.10	$ 233.66	$ 246.10	$ 2.74	$ 2.96	16%	17%
136	158	1,350	$ 149.04	$ 62.04	$ 71.85	$ 211.08	$ 220.89	$ 168.00	$ 78.68	$ 91.12	$ 246.68	$ 259.12	$ 2.97	$ 3.19	17%	17%
159	180	1,545	$ 149.04	$ 72.30	$ 82.11	$ 221.34	$ 231.15	$ 168.00	$ 91.70	$ 104.14	$ 259.70	$ 272.14	$ 3.20	$ 3.42	17%	18%
181	203	1,663	$ 149.04	$ 82.56	$ 92.37	$ 231.60	$ 241.41	$ 168.00	$ 104.72	$ 117.15	$ 272.72	$ 285.15	$ 3.43	$ 3.65	18%	18%
204	225	1,806	$ 149.04	$ 92.83	$ 102.64	$ 241.87	$ 251.68	$ 168.00	$ 117.73	$ 130.17	$ 285.73	$ 298.17	$ 3.66	$ 3.87	18%	18%
226	248	1,965	$ 149.04	$ 103.09	$ 112.90	$ 252.13	$ 261.94	$ 168.00	$ 130.75	$ 143.19	$ 298.75	$ 311.19	$ 3.88	$ 4.10	18%	19%
249	270	1,976	$ 149.04	$ 113.36	$ 123.16	$ 262.40	$ 272.20	$ 168.00	$ 143.77	$ 156.21	$ 311.77	$ 324.21	$ 4.11	$ 4.33	19%	19%
271	293	2,013	$ 149.04	$ 123.62	$ 133.43	$ 272.66	$ 282.47	$ 168.00	$ 156.78	$ 169.22	$ 324.78	$ 337.22	$ 4.34	$ 4.56	19%	19%
294	315	2,080	$ 149.04	$ 133.88	$ 143.69	$ 282.92	$ 292.73	$ 168.00	$ 169.80	$ 182.24	$ 337.80	$ 350.24	$ 4.57	$ 4.79	19%	20%
316	338	1,912	$ 149.04	$ 144.15	$ 153.95	$ 293.19	$ 302.99	$ 168.00	$ 182.82	$ 195.26	$ 350.82	$ 363.26	$ 4.80	$ 5.02	20%	20%
339	360	1,835	$ 149.04	$ 154.41	$ 164.22	$ 303.45	$ 313.26	$ 168.00	$ 195.84	$ 208.27	$ 363.84	$ 376.27	$ 5.03	$ 5.25	20%	20%
361	468	7,278	$ 149.04	$ 164.67	$ 213.62	$ 313.71	$ 362.66	$ 328.80	$ 47.61	$ 61.76	$ 376.41	$ 390.56	$ 5.22	$ 2.32	20%	8%
469	577	4,181	$ 149.04	$ 214.08	$ 263.02	$ 363.12	$ 412.06	$ 328.80	$ 61.89	$ 76.04	$ 390.69	$ 404.84	$ 2.30	$ (0.60)	8%	-2%
578	685	2,250	$ 149.04	$ 263.48	$ 312.43	$ 412.52	$ 461.47	$ 328.80	$ 76.17	$ 90.32	$ 404.97	$ 419.12	$ (0.63)	$ (3.53)	-2%	-9%
686	793	1,222	$ 149.04	$ 312.88	$ 361.83	$ 461.92	$ 510.87	$ 328.80	$ 90.45	$ 104.60	$ 419.25	$ 433.40	$ (3.56)	$ (6.46)	-9%	-15%
794	902	593	$ 149.04	$ 362.29	$ 411.23	$ 511.33	$ 560.27	$ 328.80	$ 104.73	$ 118.88	$ 433.53	$ 447.68	$ (6.48)	$ (9.38)	-15%	-20%
903	1,010	285	$ 149.04	$ 411.69	$ 460.64	$ 560.73	$ 609.68	$ 328.80	$ 119.01	$ 133.16	$ 447.81	$ 461.96	$ (9.41)	$ (12.31)	-20%	-24%
1,011	1,118	188	$ 149.04	$ 461.09	$ 510.04	$ 610.13	$ 659.08	$ 328.80	$ 133.30	$ 147.45	$ 462.10	$ 476.25	$ (12.34)	$ (15.24)	-24%	-28%
1,119	1,226	92	$ 149.04	$ 510.50	$ 559.45	$ 659.54	$ 708.49	$ 328.80	$ 147.58	$ 161.73	$ 476.38	$ 490.53	$ (15.26)	$ (18.16)	-28%	-31%
1,227	1,335	60	$ 149.04	$ 559.90	$ 608.85	$ 708.94	$ 757.89	$ 328.80	$ 161.86	$ 176.01	$ 490.66	$ 504.81	$ (18.19)	$ (21.09)	-31%	-33%
1,336	1,443	36	$ 149.04	$ 609.30	$ 658.25	$ 758.34	$ 807.29	$ 328.80	$ 176.14	$ 190.29	$ 504.94	$ 519.09	$ (21.12)	$ (24.02)	-33%	-36%
1,444	1,551	21	$ 149.04	$ 658.71	$ 707.66	$ 807.75	$ 856.70	$ 328.80	$ 190.42	$ 204.57	$ 519.22	$ 533.37	$ (24.04)	$ (26.94)	-36%	-38%
1,552	1,660	16	$ 149.04	$ 708.11	$ 757.06	$ 857.15	$ 906.10	$ 328.80	$ 204.71	$ 218.86	$ 533.51	$ 547.66	$ (26.97)	$ (29.87)	-38%	-40%
1,661	1,768	11	$ 149.04	$ 757.51	$ 806.46	$ 906.55	$ 955.50	$ 328.80	$ 218.99	$ 233.14	$ 547.79	$ 561.94	$ (29.90)	$ (32.80)	-40%	-41%
1,769	1,876	22	$ 149.04	$ 806.92	$ 855.87	$ 955.96	$ 1,004.91	$ 328.80	$ 233.27	$ 247.42	$ 562.07	$ 576.22	$ (32.82)	$ (35.72)	-41%	-43%
1,877	4,151	41	$ 149.04	$ 856.32	$ 1,893.34	$ 1,005.36	$ 2,042.38	$ 328.80	$ 247.55	$ 547.34	$ 576.35	$ 876.14	$ (35.75)	$ (97.19)	-43%	-57%

A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of GCSA A/B Rate Relative to Existing GCSA Environs Rates

								$ 14.00	$ 0.57854	$ 0.57854	Res A					
			$ 14.00	$ 0.40680	$ 0.40680			$ 27.40	$ 0.13187	$ 0.13187	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	23	41	$ 168.00	$ -	$ 9.15	$ 168.00	$ 177.15	$ 168.00	$ -	$ 13.02	$ 168.00	$ 181.02	$ -	$ 0.32	0%	2%
24	45	23	$ 168.00	$ 9.56	$ 18.31	$ 177.56	$ 186.31	$ 168.00	$ 13.60	$ 26.03	$ 181.60	$ 194.03	$ 0.34	$ 0.64	2%	4%
46	68	28	$ 168.00	$ 18.71	$ 27.46	$ 186.71	$ 195.46	$ 168.00	$ 26.61	$ 39.05	$ 194.61	$ 207.05	$ 0.66	$ 0.97	4%	6%
69	90	28	$ 168.00	$ 27.87	$ 36.61	$ 195.87	$ 204.61	$ 168.00	$ 39.63	$ 52.07	$ 207.63	$ 220.07	$ 0.98	$ 1.29	6%	8%
91	113	32	$ 168.00	$ 37.02	$ 45.77	$ 205.02	$ 213.77	$ 168.00	$ 52.65	$ 65.09	$ 220.65	$ 233.09	$ 1.30	$ 1.61	8%	9%
114	135	34	$ 168.00	$ 46.17	$ 54.92	$ 214.17	$ 222.92	$ 168.00	$ 65.66	$ 78.10	$ 233.66	$ 246.10	$ 1.62	$ 1.93	9%	10%
136	158	37	$ 168.00	$ 55.32	$ 64.07	$ 223.32	$ 232.07	$ 168.00	$ 78.68	$ 91.12	$ 246.68	$ 259.12	$ 1.95	$ 2.25	10%	12%
159	180	43	$ 168.00	$ 64.48	$ 73.22	$ 232.48	$ 241.22	$ 168.00	$ 91.70	$ 104.14	$ 259.70	$ 272.14	$ 2.27	$ 2.58	12%	13%
181	203	46	$ 168.00	$ 73.63	$ 82.38	$ 241.63	$ 250.38	$ 168.00	$ 104.72	$ 117.15	$ 272.72	$ 285.15	$ 2.59	$ 2.90	13%	14%
204	225	50	$ 168.00	$ 82.78	$ 91.53	$ 250.78	$ 259.53	$ 168.00	$ 117.73	$ 130.17	$ 285.73	$ 298.17	$ 2.91	$ 3.22	14%	15%
226	248	55	$ 168.00	$ 91.94	$ 100.68	$ 259.94	$ 268.68	$ 168.00	$ 130.75	$ 143.19	$ 298.75	$ 311.19	$ 3.23	$ 3.54	15%	16%
249	270	55	$ 168.00	$ 101.09	$ 109.84	$ 269.09	$ 277.84	$ 168.00	$ 143.77	$ 156.21	$ 311.77	$ 324.21	$ 3.56	$ 3.86	16%	17%
271	293	56	$ 168.00	$ 110.24	$ 118.99	$ 278.24	$ 286.99	$ 168.00	$ 156.78	$ 169.22	$ 324.78	$ 337.22	$ 3.88	$ 4.19	17%	18%
294	315	58	$ 168.00	$ 119.40	$ 128.14	$ 287.40	$ 296.14	$ 168.00	$ 169.80	$ 182.24	$ 337.80	$ 350.24	$ 4.20	$ 4.51	18%	18%
316	338	53	$ 168.00	$ 128.55	$ 137.30	$ 296.55	$ 305.30	$ 168.00	$ 182.82	$ 195.26	$ 350.82	$ 363.26	$ 4.52	$ 4.83	18%	19%
339	360	51	$ 168.00	$ 137.70	$ 146.45	$ 305.70	$ 314.45	$ 168.00	$ 195.84	$ 208.27	$ 363.84	$ 376.27	$ 4.84	$ 5.15	19%	20%
361	468	202	$ 168.00	$ 146.85	$ 190.51	$ 314.85	$ 358.51	$ 328.80	$ 47.61	$ 61.76	$ 376.41	$ 390.56	$ 5.13	$ 2.67	20%	9%
469	577	116	$ 168.00	$ 190.91	$ 234.56	$ 358.91	$ 402.56	$ 328.80	$ 61.89	$ 76.04	$ 390.69	$ 404.84	$ 2.65	$ 0.19	9%	1%
578	685	62	$ 168.00	$ 234.97	$ 278.62	$ 402.97	$ 446.62	$ 328.80	$ 76.17	$ 90.32	$ 404.97	$ 419.12	$ 0.17	$ (2.29)	0%	-6%
686	793	34	$ 168.00	$ 279.03	$ 322.68	$ 447.03	$ 490.68	$ 328.80	$ 90.45	$ 104.60	$ 419.25	$ 433.40	$ (2.31)	$ (4.77)	-6%	-12%
794	902	16	$ 168.00	$ 323.09	$ 366.74	$ 491.09	$ 534.74	$ 328.80	$ 104.73	$ 118.88	$ 433.53	$ 447.68	$ (4.80)	$ (7.25)	-12%	-16%
903	1,010	8	$ 168.00	$ 367.14	$ 410.79	$ 535.14	$ 578.79	$ 328.80	$ 119.01	$ 133.16	$ 447.81	$ 461.96	$ (7.28)	$ (9.74)	-16%	-20%
1,011	1,118	5	$ 168.00	$ 411.20	$ 454.85	$ 579.20	$ 622.85	$ 328.80	$ 133.30	$ 147.45	$ 462.10	$ 476.25	$ (9.76)	$ (12.22)	-20%	-24%
1,119	1,226	3	$ 168.00	$ 455.26	$ 498.91	$ 623.26	$ 666.91	$ 328.80	$ 147.58	$ 161.73	$ 476.38	$ 490.53	$ (12.24)	$ (14.70)	-24%	-26%
1,227	1,335	2	$ 168.00	$ 499.32	$ 542.97	$ 667.32	$ 710.97	$ 328.80	$ 161.86	$ 176.01	$ 490.66	$ 504.81	$ (14.72)	$ (17.18)	-26%	-29%
1,336	1,443	1	$ 168.00	$ 543.37	$ 587.02	$ 711.37	$ 755.02	$ 328.80	$ 176.14	$ 190.29	$ 504.94	$ 519.09	$ (17.20)	$ (19.66)	-29%	-31%
1,444	1,551	1	$ 168.00	$ 587.43	$ 631.08	$ 755.43	$ 799.08	$ 328.80	$ 190.42	$ 204.57	$ 519.22	$ 533.37	$ (19.68)	$ (22.14)	-31%	-33%
1,552	1,660	0	$ 168.00	$ 631.49	$ 675.14	$ 799.49	$ 843.14	$ 328.80	$ 204.71	$ 218.86	$ 533.51	$ 547.66	$ (22.17)	$ (24.62)	-33%	-35%
1,661	1,768	0	$ 168.00	$ 675.55	$ 719.20	$ 843.55	$ 887.20	$ 328.80	$ 218.99	$ 233.14	$ 547.79	$ 561.94	$ (24.65)	$ (27.10)	-35%	-37%
1,769	1,876	1	$ 168.00	$ 719.60	$ 763.25	$ 887.60	$ 931.25	$ 328.80	$ 233.27	$ 247.42	$ 562.07	$ 576.22	$ (27.13)	$ (29.59)	-37%	-38%
1,877	4,151	1	$ 168.00	$ 763.66	$ 1,688.46	$ 931.66	$ 1,856.46	$ 328.80	$ 247.55	$ 547.34	$ 576.35	$ 876.14	$ (29.61)	$ (81.69)	-38%	-53%

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A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of GCSA A/B Rate Relative to Existing City of Beaumont Rates

								$ 14.00	$ 0.57854	$ 0.57854	Res A					
			$ 12.10	$ 0.45616	$ 0.45616			$ 27.40	$ 0.13187	$ 0.13187	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	23	41	$ 145.20	$ -	$ 10.26	$ 145.20	$ 155.46	$ 168.00	$ -	$ 13.02	$ 168.00	$ 181.02	$ 1.90	$ 2.13	16%	16%
24	45	23	$ 145.20	$ 10.72	$ 20.53	$ 155.92	$ 165.73	$ 168.00	$ 13.60	$ 26.03	$ 181.60	$ 194.03	$ 2.14	$ 2.36	16%	17%
46	68	28	$ 145.20	$ 20.98	$ 30.79	$ 166.18	$ 175.99	$ 168.00	$ 26.61	$ 39.05	$ 194.61	$ 207.05	$ 2.37	$ 2.59	17%	18%
69	90	28	$ 145.20	$ 31.25	$ 41.05	$ 176.45	$ 186.25	$ 168.00	$ 39.63	$ 52.07	$ 207.63	$ 220.07	$ 2.60	$ 2.82	18%	18%
91	113	32	$ 145.20	$ 41.51	$ 51.32	$ 186.71	$ 196.52	$ 168.00	$ 52.65	$ 65.09	$ 220.65	$ 233.09	$ 2.83	$ 3.05	18%	19%
114	135	34	$ 145.20	$ 51.77	$ 61.58	$ 196.97	$ 206.78	$ 168.00	$ 65.66	$ 78.10	$ 233.66	$ 246.10	$ 3.06	$ 3.28	19%	19%
136	158	37	$ 145.20	$ 62.04	$ 71.85	$ 207.24	$ 217.05	$ 168.00	$ 78.68	$ 91.12	$ 246.68	$ 259.12	$ 3.29	$ 3.51	19%	19%
159	180	43	$ 145.20	$ 72.30	$ 82.11	$ 217.50	$ 227.31	$ 168.00	$ 91.70	$ 104.14	$ 259.70	$ 272.14	$ 3.52	$ 3.74	19%	20%
181	203	46	$ 145.20	$ 82.56	$ 92.37	$ 227.76	$ 237.57	$ 168.00	$ 104.72	$ 117.15	$ 272.72	$ 285.15	$ 3.75	$ 3.97	20%	20%
204	225	50	$ 145.20	$ 92.83	$ 102.64	$ 238.03	$ 247.84	$ 168.00	$ 117.73	$ 130.17	$ 285.73	$ 298.17	$ 3.98	$ 4.19	20%	20%
226	248	55	$ 145.20	$ 103.09	$ 112.90	$ 248.29	$ 258.10	$ 168.00	$ 130.75	$ 143.19	$ 298.75	$ 311.19	$ 4.20	$ 4.42	20%	21%
249	270	55	$ 145.20	$ 113.36	$ 123.16	$ 258.56	$ 268.36	$ 168.00	$ 143.77	$ 156.21	$ 311.77	$ 324.21	$ 4.43	$ 4.65	21%	21%
271	293	56	$ 145.20	$ 123.62	$ 133.43	$ 268.82	$ 278.63	$ 168.00	$ 156.78	$ 169.22	$ 324.78	$ 337.22	$ 4.66	$ 4.88	21%	21%
294	315	58	$ 145.20	$ 133.88	$ 143.69	$ 279.08	$ 288.89	$ 168.00	$ 169.80	$ 182.24	$ 337.80	$ 350.24	$ 4.89	$ 5.11	21%	21%
316	338	53	$ 145.20	$ 144.15	$ 153.95	$ 289.35	$ 299.15	$ 168.00	$ 182.82	$ 195.26	$ 350.82	$ 363.26	$ 5.12	$ 5.34	21%	21%
339	360	51	$ 145.20	$ 154.41	$ 164.22	$ 299.61	$ 309.42	$ 168.00	$ 195.84	$ 208.27	$ 363.84	$ 376.27	$ 5.35	$ 5.57	21%	22%
361	468	202	$ 145.20	$ 164.67	$ 213.62	$ 309.87	$ 358.82	$ 328.80	$ 47.61	$ 61.76	$ 376.41	$ 390.56	$ 5.54	$ 2.64	21%	9%
469	577	116	$ 145.20	$ 214.08	$ 263.02	$ 359.28	$ 408.22	$ 328.80	$ 61.89	$ 76.04	$ 390.69	$ 404.84	$ 2.62	$ (0.28)	9%	-1%
578	685	62	$ 145.20	$ 263.48	$ 312.43	$ 408.68	$ 457.63	$ 328.80	$ 76.17	$ 90.32	$ 404.97	$ 419.12	$ (0.31)	$ (3.21)	-1%	-8%
686	793	34	$ 145.20	$ 312.88	$ 361.83	$ 458.08	$ 507.03	$ 328.80	$ 90.45	$ 104.60	$ 419.25	$ 433.40	$ (3.24)	$ (6.14)	-8%	-15%
794	902	16	$ 145.20	$ 362.29	$ 411.23	$ 507.49	$ 556.43	$ 328.80	$ 104.73	$ 118.88	$ 433.53	$ 447.68	$ (6.16)	$ (9.06)	-15%	-20%
903	1,010	8	$ 145.20	$ 411.69	$ 460.64	$ 556.89	$ 605.84	$ 328.80	$ 119.01	$ 133.16	$ 447.81	$ 461.96	$ (9.09)	$ (11.99)	-20%	-24%
1,011	1,118	5	$ 145.20	$ 461.09	$ 510.04	$ 606.29	$ 655.24	$ 328.80	$ 133.30	$ 147.45	$ 462.10	$ 476.25	$ (12.02)	$ (14.92)	-24%	-27%
1,119	1,226	3	$ 145.20	$ 510.50	$ 559.45	$ 655.70	$ 704.65	$ 328.80	$ 147.58	$ 161.73	$ 476.38	$ 490.53	$ (14.94)	$ (17.84)	-27%	-30%
1,227	1,335	2	$ 145.20	$ 559.90	$ 608.85	$ 705.10	$ 754.05	$ 328.80	$ 161.86	$ 176.01	$ 490.66	$ 504.81	$ (17.87)	$ (20.77)	-30%	-33%
1,336	1,443	1	$ 145.20	$ 609.30	$ 658.25	$ 754.50	$ 803.45	$ 328.80	$ 176.14	$ 190.29	$ 504.94	$ 519.09	$ (20.80)	$ (23.70)	-33%	-35%
1,444	1,551	1	$ 145.20	$ 658.71	$ 707.66	$ 803.91	$ 852.86	$ 328.80	$ 190.42	$ 204.57	$ 519.22	$ 533.37	$ (23.72)	$ (26.62)	-35%	-37%
1,552	1,660	0	$ 145.20	$ 708.11	$ 757.06	$ 853.31	$ 902.26	$ 328.80	$ 204.71	$ 218.86	$ 533.51	$ 547.66	$ (26.65)	$ (29.55)	-37%	-39%
1,661	1,768	0	$ 145.20	$ 757.51	$ 806.46	$ 902.71	$ 951.66	$ 328.80	$ 218.99	$ 233.14	$ 547.79	$ 561.94	$ (29.58)	$ (32.48)	-39%	-41%
1,769	1,876	1	$ 145.20	$ 806.92	$ 855.87	$ 952.12	$ 1,001.07	$ 328.80	$ 233.27	$ 247.42	$ 562.07	$ 576.22	$ (32.50)	$ (35.40)	-41%	-42%
1,877	4,151	1	$ 145.20	$ 856.32	$ 1,893.34	$ 1,001.52	$ 2,038.54	$ 328.80	$ 247.55	$ 547.34	$ 576.35	$ 876.14	$ (35.43)	$ (96.87)	-42%	-57%

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A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADIONAL RATE STRUCTURE

Annual Residential Bill Impacts of GCSA Incorporated A/B Rate Structure Compared to Traditional Rate Structure

								$ 14.00	$ 0.57854	$ 0.57854	Res A					
			$ 18.81	$ 0.31163	$ 0.31163			$ 27.40	$ 0.13187	$ 0.13187	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	23	1,478	$ 225.72	$ -	$ 7.01	$ 225.72	$ 232.73	$ 168.00	$ -	$ 13.02	$ 168.00	$ 181.02	$ (4.81)	$ (4.31)	-26%	-22%
24	45	844	$ 225.72	$ 7.32	$ 14.02	$ 233.04	$ 239.74	$ 168.00	$ 13.60	$ 26.03	$ 181.60	$ 194.03	$ (4.29)	$ (3.81)	-22%	-19%
46	68	1,024	$ 225.72	$ 14.33	$ 21.04	$ 240.05	$ 246.76	$ 168.00	$ 26.61	$ 39.05	$ 194.61	$ 207.05	$ (3.79)	$ (3.31)	-19%	-16%
69	90	1,014	$ 225.72	$ 21.35	$ 28.05	$ 247.07	$ 253.77	$ 168.00	$ 39.63	$ 52.07	$ 207.63	$ 220.07	$ (3.29)	$ (2.81)	-16%	-13%
91	113	1,154	$ 225.72	$ 28.36	$ 35.06	$ 254.08	$ 260.78	$ 168.00	$ 52.65	$ 65.09	$ 220.65	$ 233.09	$ (2.79)	$ (2.31)	-13%	-11%
114	135	1,229	$ 225.72	$ 35.37	$ 42.07	$ 261.09	$ 267.79	$ 168.00	$ 65.66	$ 78.10	$ 233.66	$ 246.10	$ (2.29)	$ (1.81)	-11%	-8%
136	158	1,350	$ 225.72	$ 42.38	$ 49.08	$ 268.10	$ 274.80	$ 168.00	$ 78.68	$ 91.12	$ 246.68	$ 259.12	$ (1.79)	$ (1.31)	-8%	-6%
159	180	1,545	$ 225.72	$ 49.39	$ 56.09	$ 275.11	$ 281.81	$ 168.00	$ 91.70	$ 104.14	$ 259.70	$ 272.14	$ (1.28)	$ (0.81)	-6%	-3%
181	203	1,663	$ 225.72	$ 56.41	$ 63.11	$ 282.13	$ 288.83	$ 168.00	$ 104.72	$ 117.15	$ 272.72	$ 285.15	$ (0.78)	$ (0.31)	-3%	-1%
204	225	1,806	$ 225.72	$ 63.42	$ 70.12	$ 289.14	$ 295.84	$ 168.00	$ 117.73	$ 130.17	$ 285.73	$ 298.17	$ (0.28)	$ 0.19	-1%	1%
226	248	1,965	$ 225.72	$ 70.43	$ 77.13	$ 296.15	$ 302.85	$ 168.00	$ 130.75	$ 143.19	$ 298.75	$ 311.19	$ 0.22	$ 0.70	1%	3%
249	270	1,976	$ 225.72	$ 77.44	$ 84.14	$ 303.16	$ 309.86	$ 168.00	$ 143.77	$ 156.21	$ 311.77	$ 324.21	$ 0.72	$ 1.20	3%	5%
271	293	2,013	$ 225.72	$ 84.45	$ 91.15	$ 310.17	$ 316.87	$ 168.00	$ 156.78	$ 169.22	$ 324.78	$ 337.22	$ 1.22	$ 1.70	5%	6%
294	315	2,080	$ 225.72	$ 91.46	$ 98.16	$ 317.18	$ 323.88	$ 168.00	$ 169.80	$ 182.24	$ 337.80	$ 350.24	$ 1.72	$ 2.20	7%	8%
316	338	1,911	$ 225.72	$ 98.48	$ 105.18	$ 324.20	$ 330.90	$ 168.00	$ 182.82	$ 195.26	$ 350.82	$ 363.26	$ 2.22	$ 2.70	8%	10%
339	360	1,835	$ 225.72	$ 105.49	$ 112.19	$ 331.21	$ 337.91	$ 168.00	$ 195.84	$ 208.27	$ 363.84	$ 376.27	$ 2.72	$ 3.20	10%	11%
361	468	7,278	$ 225.72	$ 112.50	$ 145.94	$ 338.22	$ 371.66	$ 328.80	$ 47.61	$ 61.76	$ 376.41	$ 390.56	$ 3.18	$ 1.57	11%	5%
469	577	4,181	$ 225.72	$ 146.25	$ 179.69	$ 371.97	$ 405.41	$ 328.80	$ 61.89	$ 76.04	$ 390.69	$ 404.84	$ 1.56	$ (0.05)	5%	0%
578	685	2,250	$ 225.72	$ 180.00	$ 213.44	$ 405.72	$ 439.16	$ 328.80	$ 76.17	$ 90.32	$ 404.97	$ 419.12	$ (0.06)	$ (1.67)	0%	-5%
686	793	1,222	$ 225.72	$ 213.75	$ 247.19	$ 439.47	$ 472.91	$ 328.80	$ 90.45	$ 104.60	$ 419.25	$ 433.40	$ (1.68)	$ (3.29)	-5%	-8%
794	902	593	$ 225.72	$ 247.50	$ 280.94	$ 473.22	$ 506.66	$ 328.80	$ 104.73	$ 118.88	$ 433.53	$ 447.68	$ (3.31)	$ (4.91)	-8%	-12%
903	1,010	285	$ 225.72	$ 281.25	$ 314.69	$ 506.97	$ 540.41	$ 328.80	$ 119.01	$ 133.16	$ 447.81	$ 461.96	$ (4.93)	$ (6.54)	-12%	-15%
1,011	1,118	188	$ 225.72	$ 315.00	$ 348.44	$ 540.72	$ 574.16	$ 328.80	$ 133.30	$ 147.45	$ 462.10	$ 476.25	$ (6.55)	$ (8.16)	-15%	-17%
1,119	1,226	92	$ 225.72	$ 348.75	$ 382.19	$ 574.47	$ 607.91	$ 328.80	$ 147.58	$ 161.73	$ 476.38	$ 490.53	$ (8.17)	$ (9.78)	-17%	-19%
1,227	1,335	60	$ 225.72	$ 382.50	$ 415.94	$ 608.22	$ 641.66	$ 328.80	$ 161.86	$ 176.01	$ 490.66	$ 504.81	$ (9.80)	$ (11.40)	-19%	-21%
1,336	1,443	36	$ 225.72	$ 416.25	$ 449.69	$ 641.97	$ 675.41	$ 328.80	$ 176.14	$ 190.29	$ 504.94	$ 519.09	$ (11.42)	$ (13.03)	-21%	-23%
1,444	1,551	21	$ 225.72	$ 450.00	$ 483.44	$ 675.72	$ 709.16	$ 328.80	$ 190.42	$ 204.57	$ 519.22	$ 533.37	$ (13.04)	$ (14.65)	-23%	-25%
1,552	1,660	16	$ 225.72	$ 483.75	$ 517.19	$ 709.47	$ 742.91	$ 328.80	$ 204.71	$ 218.86	$ 533.51	$ 547.66	$ (14.66)	$ (16.27)	-25%	-26%
1,661	1,768	11	$ 225.72	$ 517.50	$ 550.94	$ 743.22	$ 776.66	$ 328.80	$ 218.99	$ 233.14	$ 547.79	$ 561.94	$ (16.29)	$ (17.89)	-26%	-28%
1,769	1,876	22	$ 225.72	$ 551.25	$ 584.69	$ 776.97	$ 810.41	$ 328.80	$ 233.27	$ 247.42	$ 562.07	$ 576.22	$ (17.91)	$ (19.52)	-28%	-29%
1,877	4,151	41	$ 225.72	$ 585.00	$ 1,293.45	$ 810.72	$ 1,519.17	$ 328.80	$ 247.55	$ 547.34	$ 576.35	$ 876.14	$ (19.53)	$ (53.59)	-29%	-42%

A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADIONAL RATE STRUCTURE

Annual Residential Bill Impacts of GCSA Environs A/B Rate Structure Compared to Traditional Rate Structure

								$ 14.00	$ 0.57854	$ 0.57854	Res A					
			$ 18.81	$ 0.31163	$ 0.31163			$ 27.40	$ 0.13187	$ 0.13187	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	23	41	$ 225.72	$ -	$ 7.01	$ 225.72	$ 232.73	$ 168.00	$ -	$ 13.02	$ 168.00	$ 181.02	$ (4.81)	$ (4.31)	-26%	-22%
24	45	23	$ 225.72	$ 7.32	$ 14.02	$ 233.04	$ 239.74	$ 168.00	$ 13.60	$ 26.03	$ 181.60	$ 194.03	$ (4.29)	$ (3.81)	-22%	-19%
46	68	28	$ 225.72	$ 14.33	$ 21.04	$ 240.05	$ 246.76	$ 168.00	$ 26.61	$ 39.05	$ 194.61	$ 207.05	$ (3.79)	$ (3.31)	-19%	-16%
69	90	28	$ 225.72	$ 21.35	$ 28.05	$ 247.07	$ 253.77	$ 168.00	$ 39.63	$ 52.07	$ 207.63	$ 220.07	$ (3.29)	$ (2.81)	-16%	-13%
91	113	32	$ 225.72	$ 28.36	$ 35.06	$ 254.08	$ 260.78	$ 168.00	$ 52.65	$ 65.09	$ 220.65	$ 233.09	$ (2.79)	$ (2.31)	-13%	-11%
114	135	34	$ 225.72	$ 35.37	$ 42.07	$ 261.09	$ 267.79	$ 168.00	$ 65.66	$ 78.10	$ 233.66	$ 246.10	$ (2.29)	$ (1.81)	-11%	-8%
136	158	37	$ 225.72	$ 42.38	$ 49.08	$ 268.10	$ 274.80	$ 168.00	$ 78.68	$ 91.12	$ 246.68	$ 259.12	$ (1.79)	$ (1.31)	-8%	-6%
159	180	43	$ 225.72	$ 49.39	$ 56.09	$ 275.11	$ 281.81	$ 168.00	$ 91.70	$ 104.14	$ 259.70	$ 272.14	$ (1.28)	$ (0.81)	-6%	-3%
181	203	46	$ 225.72	$ 56.41	$ 63.11	$ 282.13	$ 288.83	$ 168.00	$ 104.72	$ 117.15	$ 272.72	$ 285.15	$ (0.78)	$ (0.31)	-3%	-1%
204	225	50	$ 225.72	$ 63.42	$ 70.12	$ 289.14	$ 295.84	$ 168.00	$ 117.73	$ 130.17	$ 285.73	$ 298.17	$ (0.28)	$ 0.19	-1%	1%
226	248	55	$ 225.72	$ 70.43	$ 77.13	$ 296.15	$ 302.85	$ 168.00	$ 130.75	$ 143.19	$ 298.75	$ 311.19	$ 0.22	$ 0.70	1%	3%
249	270	55	$ 225.72	$ 77.44	$ 84.14	$ 303.16	$ 309.86	$ 168.00	$ 143.77	$ 156.21	$ 311.77	$ 324.21	$ 0.72	$ 1.20	3%	5%
271	293	56	$ 225.72	$ 84.45	$ 91.15	$ 310.17	$ 316.87	$ 168.00	$ 156.78	$ 169.22	$ 324.78	$ 337.22	$ 1.22	$ 1.70	5%	6%
294	315	58	$ 225.72	$ 91.46	$ 98.16	$ 317.18	$ 323.88	$ 168.00	$ 169.80	$ 182.24	$ 337.80	$ 350.24	$ 1.72	$ 2.20	7%	8%
316	338	53	$ 225.72	$ 98.48	$ 105.18	$ 324.20	$ 330.90	$ 168.00	$ 182.82	$ 195.26	$ 350.82	$ 363.26	$ 2.22	$ 2.70	8%	10%
339	360	51	$ 225.72	$ 105.49	$ 112.19	$ 331.21	$ 337.91	$ 168.00	$ 195.84	$ 208.27	$ 363.84	$ 376.27	$ 2.72	$ 3.20	10%	11%
361	468	202	$ 225.72	$ 112.50	$ 145.94	$ 338.22	$ 371.66	$ 328.80	$ 47.61	$ 61.76	$ 376.41	$ 390.56	$ 3.18	$ 1.57	11%	5%
469	577	116	$ 225.72	$ 146.25	$ 179.69	$ 371.97	$ 405.41	$ 328.80	$ 61.89	$ 76.04	$ 390.69	$ 404.84	$ 1.56	$ (0.05)	5%	0%
578	685	62	$ 225.72	$ 180.00	$ 213.44	$ 405.72	$ 439.16	$ 328.80	$ 76.17	$ 90.32	$ 404.97	$ 419.12	$ (0.06)	$ (1.67)	0%	-5%
686	793	34	$ 225.72	$ 213.75	$ 247.19	$ 439.47	$ 472.91	$ 328.80	$ 90.45	$ 104.60	$ 419.25	$ 433.40	$ (1.68)	$ (3.29)	-5%	-8%
794	902	16	$ 225.72	$ 247.50	$ 280.94	$ 473.22	$ 506.66	$ 328.80	$ 104.73	$ 118.88	$ 433.53	$ 447.68	$ (3.31)	$ (4.91)	-8%	-12%
903	1,010	8	$ 225.72	$ 281.25	$ 314.69	$ 506.97	$ 540.41	$ 328.80	$ 119.01	$ 133.16	$ 447.81	$ 461.96	$ (4.93)	$ (6.54)	-12%	-15%
1,011	1,118	5	$ 225.72	$ 315.00	$ 348.44	$ 540.72	$ 574.16	$ 328.80	$ 133.30	$ 147.45	$ 462.10	$ 476.25	$ (6.55)	$ (8.16)	-15%	-17%
1,119	1,226	3	$ 225.72	$ 348.75	$ 382.19	$ 574.47	$ 607.91	$ 328.80	$ 147.58	$ 161.73	$ 476.38	$ 490.53	$ (8.17)	$ (9.78)	-17%	-19%
1,227	1,335	2	$ 225.72	$ 382.50	$ 415.94	$ 608.22	$ 641.66	$ 328.80	$ 161.86	$ 176.01	$ 490.66	$ 504.81	$ (9.80)	$ (11.40)	-19%	-21%
1,336	1,443	1	$ 225.72	$ 416.25	$ 449.69	$ 641.97	$ 675.41	$ 328.80	$ 176.14	$ 190.29	$ 504.94	$ 519.09	$ (11.42)	$ (13.03)	-21%	-23%
1,444	1,551	1	$ 225.72	$ 450.00	$ 483.44	$ 675.72	$ 709.16	$ 328.80	$ 190.42	$ 204.57	$ 519.22	$ 533.37	$ (13.04)	$ (14.65)	-23%	-25%
1,552	1,660	0	$ 225.72	$ 483.75	$ 517.19	$ 709.47	$ 742.91	$ 328.80	$ 204.71	$ 218.86	$ 533.51	$ 547.66	$ (14.66)	$ (16.27)	-25%	-26%
1,661	1,768	0	$ 225.72	$ 517.50	$ 550.94	$ 743.22	$ 776.66	$ 328.80	$ 218.99	$ 233.14	$ 547.79	$ 561.94	$ (16.29)	$ (17.89)	-26%	-28%
1,769	1,876	1	$ 225.72	$ 551.25	$ 584.69	$ 776.97	$ 810.41	$ 328.80	$ 233.27	$ 247.42	$ 562.07	$ 576.22	$ (17.91)	$ (19.52)	-28%	-29%
1,877	4,151	1	$ 225.72	$ 585.00	$ 1,293.45	$ 810.72	$ 1,519.17	$ 328.80	$ 247.55	$ 547.34	$ 576.35	$ 876.14	$ (19.53)	$ (53.59)	-29%	-42%

A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF COAST SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30,2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADIONAL RATE STRUCTURE

Annual Residential Bill Impacts of City of Beaumont A/B Rate Structure Compared to Traditional Rate Structure

								$ 14.00	$ 0.57854	$ 0.57854 Res A						
			$ 18.81	$ 0.31163	$ 0.31163			$ 27.40	$ 0.13187	$ 0.13187 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	23	-	$ 225.72	$ -	$ 7.01	$ 225.72	$ 232.73	$ 168.00	$ -	$ 13.02	$ 168.00	$ 181.02	$ (4.81)	$ (4.31)	-26%	-22%
24	45	-	$ 225.72	$ 7.32	$ 14.02	$ 233.04	$ 239.74	$ 168.00	$ 13.60	$ 26.03	$ 181.60	$ 194.03	$ (4.29)	$ (3.81)	-22%	-19%
46	68	-	$ 225.72	$ 14.33	$ 21.04	$ 240.05	$ 246.76	$ 168.00	$ 26.61	$ 39.05	$ 194.61	$ 207.05	$ (3.79)	$ (3.31)	-19%	-16%
69	90	-	$ 225.72	$ 21.35	$ 28.05	$ 247.07	$ 253.77	$ 168.00	$ 39.63	$ 52.07	$ 207.63	$ 220.07	$ (3.29)	$ (2.81)	-16%	-13%
91	113	-	$ 225.72	$ 28.36	$ 35.06	$ 254.08	$ 260.78	$ 168.00	$ 52.65	$ 65.09	$ 220.65	$ 233.09	$ (2.79)	$ (2.31)	-13%	-11%
114	135	-	$ 225.72	$ 35.37	$ 42.07	$ 261.09	$ 267.79	$ 168.00	$ 65.66	$ 78.10	$ 233.66	$ 246.10	$ (2.29)	$ (1.81)	-11%	-8%
136	158	-	$ 225.72	$ 42.38	$ 49.08	$ 268.10	$ 274.80	$ 168.00	$ 78.68	$ 91.12	$ 246.68	$ 259.12	$ (1.79)	$ (1.31)	-8%	-6%
159	180	-	$ 225.72	$ 49.39	$ 56.09	$ 275.11	$ 281.81	$ 168.00	$ 91.70	$ 104.14	$ 259.70	$ 272.14	$ (1.28)	$ (0.81)	-6%	-3%
181	203	-	$ 225.72	$ 56.41	$ 63.11	$ 282.13	$ 288.83	$ 168.00	$ 104.72	$ 117.15	$ 272.72	$ 285.15	$ (0.78)	$ (0.31)	-3%	-1%
204	225	-	$ 225.72	$ 63.42	$ 70.12	$ 289.14	$ 295.84	$ 168.00	$ 117.73	$ 130.17	$ 285.73	$ 298.17	$ (0.28)	$ 0.19	-1%	1%
226	248	-	$ 225.72	$ 70.43	$ 77.13	$ 296.15	$ 302.85	$ 168.00	$ 130.75	$ 143.19	$ 298.75	$ 311.19	$ 0.22	$ 0.70	1%	3%
249	270	-	$ 225.72	$ 77.44	$ 84.14	$ 303.16	$ 309.86	$ 168.00	$ 143.77	$ 156.21	$ 311.77	$ 324.21	$ 0.72	$ 1.20	3%	5%
271	293	-	$ 225.72	$ 84.45	$ 91.15	$ 310.17	$ 316.87	$ 168.00	$ 156.78	$ 169.22	$ 324.78	$ 337.22	$ 1.22	$ 1.70	5%	6%
294	315	-	$ 225.72	$ 91.46	$ 98.16	$ 317.18	$ 323.88	$ 168.00	$ 169.80	$ 182.24	$ 337.80	$ 350.24	$ 1.72	$ 2.20	7%	8%
316	338	1	$ 225.72	$ 98.48	$ 105.18	$ 324.20	$ 330.90	$ 168.00	$ 182.82	$ 195.26	$ 350.82	$ 363.26	$ 2.22	$ 2.70	8%	10%
339	360	-	$ 225.72	$ 105.49	$ 112.19	$ 331.21	$ 337.91	$ 168.00	$ 195.84	$ 208.27	$ 363.84	$ 376.27	$ 2.72	$ 3.20	10%	11%
361	468	-	$ 225.72	$ 112.50	$ 145.94	$ 338.22	$ 371.66	$ 328.80	$ 47.61	$ 61.76	$ 376.41	$ 390.56	$ 3.18	$ 1.57	11%	5%
469	577	-	$ 225.72	$ 146.25	$ 179.69	$ 371.97	$ 405.41	$ 328.80	$ 61.89	$ 76.04	$ 390.69	$ 404.84	$ 1.56	$ (0.05)	5%	0%
578	685	-	$ 225.72	$ 180.00	$ 213.44	$ 405.72	$ 439.16	$ 328.80	$ 76.17	$ 90.32	$ 404.97	$ 419.12	$ (0.06)	$ (1.67)	0%	-5%
686	793	-	$ 225.72	$ 213.75	$ 247.19	$ 439.47	$ 472.91	$ 328.80	$ 90.45	$ 104.60	$ 419.25	$ 433.40	$ (1.68)	$ (3.29)	-5%	-8%
794	902	-	$ 225.72	$ 247.50	$ 280.94	$ 473.22	$ 506.66	$ 328.80	$ 104.73	$ 118.88	$ 433.53	$ 447.68	$ (3.31)	$ (4.91)	-8%	-12%
903	1,010	-	$ 225.72	$ 281.25	$ 314.69	$ 506.97	$ 540.41	$ 328.80	$ 119.01	$ 133.16	$ 447.81	$ 461.96	$ (4.93)	$ (6.54)	-12%	-15%
1,011	1,118	-	$ 225.72	$ 315.00	$ 348.44	$ 540.72	$ 574.16	$ 328.80	$ 133.30	$ 147.45	$ 462.10	$ 476.25	$ (6.55)	$ (8.16)	-15%	-17%
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STATE OF MARYLAND §
§
COUNTY OF MONTGOMERY §

AFFIDAVIT OF PAUL RAAB

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

1. "My name is Paul Raab. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as a Principal in Energy Tools, LLC, a consulting firm specializing in analytical economic and energy management services. 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.

Paul Raab

Paul Raab

SUBSCRIBED AND SWORN TO BEFORE ME by the said Paul Raab on this 13 day of December 2019.

Notary Public in and for the State of Maryland

WILLIAM DUNCAN
NOTARY PUBLIC
PRINCE GEORGE'S COUNTY, MD
MY COMMISSION EXPIRES
01-06-2021

GAS UTILITIES DOCKET NO. __________

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

DIRECT TESTIMONY

OF

CHRISTY M. BELL

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

December 20, 2019

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF CHRISTY M. BELL

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christy M. Bell, and my business address is 1301 South MoPac Expressway, Suite 400, Austin, Texas 78746.

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

A. I am a Rates Analyst 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 Arts degree from the University of Texas at Austin in 1999. Prior to my role at TGS I owned and managed a small business. In April 2017, I began my current role with the Company. My responsibilities include preparing rate schedules and filing them with the Railroad Commission of Texas ("Commission"), filing annual compliance reports with regulators, and preparing departmental workpapers for the Commission's quality of service audits.

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.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the rate schedules and tariffs currently in effect for the Central Texas Service Area ("CTSA"), the Gulf Coast Service Area ("GCSA") and the City of Beaumont, Texas. In addition, I describe the rate schedules and tariffs which would be applicable for the proposed Central-Gulf Service Area ("CGSA") should consolidation as proposed by the Company be approved.

Q. ARE YOU SPONSORING ANY COST OF SERVICE SCHEDULES?

A. No, I am not.

II. <u>CURRENT RATE SCHEDULES AND TARIFFS</u>

Q. WHEN WAS THE LAST GENERAL BASE RATE STATEMENT OF INTENT ("SOI") FILED IN THE EXISTING GCSA?

A. On December 30, 2015, TGS filed a SOI requesting to increase rates within the incorporated and environs areas of two previously existing service areas, (1) the Galveston Service Area ("GSA") comprised of Bayou Vista, Galveston and Jamaica Beach ("GSA Cities") and their environs, and (2) the South Jefferson County Service Area ("SJCSA") comprised of Groves, Nederland, Port Arthur, and Port Neches ("SJCSA Cities) and their environs. In that case, TGS also requested consolidation of the GSA and SJCSA to create the GCSA. The SOI was docketed at the Commission as Gas Utilities Docket ("GUD") No. 10488. The cities and

Commission approved the consolidation request and new rates for the GCSA in 2016.[1]

Q. HAS THE COMPANY REQUESTED RATE CHANGES WITH THE GCSA CITIES SINCE THE SOI IN 2015?

A. Yes. A Cost of Service Adjustment ("COSA") Clause tariff has been in effect for the GCSA Cities since April 14, 2017. Pursuant to the terms of the COSA Clause, the Company filed a COSA adjustment with the GCSA Cities on April 28, 2017 that included capital investment and expense from a test year ending December 31, 2016. The Company has continued to file annual COSA adjustments with the GCSA Cities, most recently on April 30, 2019, that included capital investment and expenses from a test year ending December 31, 2018.

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE EXISTING GCSA INCORPORATED AREAS?

A. As shown in Exhibit CMB-1, the rates in effect for customers in the incorporated areas of the GCSA are the rates that the GCSA Cities approved as part of the COSA in 2019.

[1] On May 3, 2016, the Commission issued a Final Order approving a settlement agreement reached by the parties. GUD No. 10488, Final Order (May 3, 2016). The GSA and SJCSA Cities approved as follows: Bayou Vista and Galveston approved the settlement agreement via operation of law effective May 3, 2016; Jamaica Beach approved the SOI filing via operation of law effective February 3, 2016; Port Arthur issued Ordinance No. 16-28 dated April 4, 2016; Port Neches issued Ordinance No. 2016-04 dated March 24, 2016; Nederland issued Ordinance No. 2016-13 dated March 28, 2016; and Groves issued Ordinance No. 2016-03 dated April 4, 2016.

Q. HAS THE COMPANY REQUESTED INTERIM RATE ADJUSTMENTS ("IRAs") IN THE GCSA ENVIRONS?

A. Yes. Pursuant to Texas Utilities Code § 104.301 (the "GRIP statute") and Commission Rule § 7.7101 (the "GRIP rule"), the Company filed the following initial IRAs for the GCSA environs:

GUD No.	IRA Filing Date	Plant Investment Period	Final Order Issue Date
10666	October 20, 2017	January 1 to December 31, 2016	March 20, 2018
10781	October 19, 2018	January 1 to December 31, 2017	January 23, 2019
10857	June 14, 2019	January 1 to December 31, 2018	September 11, 2019

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE EXISTING GCSA ENVIRONS?

A. As shown in Exhibit CMB-1, the rates in effect for customers in the GCSA environs are base rates approved in GUD No. 10488 and the IRAs addressed above.

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

A. On June 20, 2016, TGS filed an SOI requesting to change rates within the incorporated and environs areas of the legacy Central Texas service area ("CTX") and the environs areas of the legacy South Texas Service Area ("STSA").[2] In addition to requesting a change in rates, the Company requested to consolidate the CTX and the STSA to create the existing CTSA. The SOI was docketed at the Commission as GUD No. 10526. The CTX Cities approved the settlement

[2] The legacy CTX service area included: Austin, Bee Cave, Buda (environs only), Cedar Park, Dripping Springs, Kyle, Lakeway, Rollingwood, Sunset Valley and West Lake Hills. The legacy STSA included: Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner and Yoakum.

agreement in October, November, and December 2016[3] and the Commission approved on November 15, 2016. On December 2, 2016, the Company filed an SOI with the incorporated areas of the legacy STSA requesting to consolidate the legacy STSA incorporated areas with the CTSA and to decrease rates. The STSA Cities approved the consolidation request and rate decrease in December 2016 and January 2017.[4]

Q. HAS THE COMPANY REQUESTED IRAs IN THE EXISTING CTSA?

A. Yes. Pursuant to the GRIP statute and GRIP rule, the Company filed the following IRAs with the CTSA incorporated and environs areas:

GUD No.	IRA Filing Date	Plant Investment Period	Final Order Issue Date
10610	March 3, 2017	January 1 to December 31, 2016	June 6, 2017
10703	March 2, 2018	January 1 to December 31, 2017	June 5, 2018
10824	March 1, 2019	January 1 to December 31, 2018	June 4, 2019

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE EXISTING CTSA?

A. As shown in Exhibit CMB-1, the rates in effect for customers in the existing CTSA are the base rates approved in GUD No. 10526 and the IRAs addressed above.

[3] The CTX Cities approved the settlement agreement as follows: Austin issued Ordinance No. 20161103-077 dated November 3, 2016; Bee Cave issued Ordinance No. 320 dated October 25, 2016; Cedar Park issued Ordinance No. G03.16.11.10.E1 dated November 10, 2016; Dripping Springs issued Ordinance No. 1790.02 dated October 18, 2016; Kyle issued Ordinance No. 913 dated October 18, 2016; Lakeway issued Ordinance No. 2016-10-17-08 dated October 17, 2016; Rollingwood issued Ordinance No. 2016-10-19 dated October 19, 2016; Sunset Valley issued Ordinance No. 161101 dated November 1, 2016; and West Lake Hills issued Ordinance No. 435 dated October 26, 2016.

[4] The STSA Cities approved the consolidation request and rate decrease as follows: Cuero issued Ordinance No. 2016-24 dated January 13, 2017; Gonzales and Shiner approved via operation of law effective January 6, 2017; Lockhart issued Ordinance No. 2016-29 dated December 20, 2016; Luling issued Ordinance No. 2016-O-11 dated December 8, 2016; Nixon issued Ordinance No. 0-2016-12-12 dated December 12, 2016; and Yoakum issued Ordinance No. 2120 dated December 13, 2016.

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE CITY OF BEAUMONT?

A. On May 22, 2019, TGS filed initial rate tariffs within the incorporated areas of Beaumont that were identical to the current rates in the neighboring incorporated areas of the GCSA to remedy a coding issue in the Company's billing system in which two incorporated Beaumont customers were erroneously coded to another jurisdiction. As shown in Exhibit CMB-1, the rates in effect for customers in the incorporated areas of Beaumont are the initial rates established on May 22, 2019.

Q. IF THE COMPANY'S REQUEST REGARDING CONSOLIDATION IS APPROVED, WHAT TARIFFS WILL BE IN EFFECT FOR CUSTOMERS IN THE CTSA, GCSA, AND THE CITY OF BEAUMONT?

A. If the Company's request to consolidate the incorporated and unincorporated areas of the CTSA and GCSA and the incorporated areas of Beaumont to create the CGSA is approved, the proposed rate schedules and tariffs would be applicable to the entire CGSA, as shown in Exhibit A to the SOI filing.

If the Company's consolidation request is not approved, the Company requests that new rate schedules and tariffs are approved for the GCSA and City of Beaumont and new rate schedules and tariffs are approved for the existing CTSA, which are also provided in Exhibit A to the SOI filing.

III. PROPOSED RATE SCHEDULES AND TARIFFS

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

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

- Rate Schedules 10, 20, 30, 40, 48, 70, C-1, and CNG-1 for gas sales service;

- Rate Schedules 1Z, 2Z, 3Z, 4Z, 4H, 7Z, C-1-ENV, and CNG-1-ENV for gas sales service;
- Rate Schedules T-1, T-1-ENV, T-TERMS for transportation service;
- Rate Schedules 1-INC and 1-ENV for the cost of gas clause;
- Incorporated and environs Rules of Service;
- Rate Schedule WNA for weather normalization adjustment;
- Rate Schedule EDIT-Rider for recovery of the flow back to customers of the annual amortization of EDIT;
- Rate Schedules PIT and PIT-Rider for recovery of annually approved pipeline integrity testing expenses[5];
- Rate Schedule HARV-Rider for recovery of approved expenses related to Hurricane Harvey;
- Rate Schedules NER and NER-Rider for recovery of operation and maintenance expenses resulting from natural events;
- Rate Schedules RCE and RCE-ENV for recovery of approved rate case expenses in this filing; and
- Rate Schedule PSF for recovery of the annual fee to support the pipeline safety functions of the Commission.

The rate schedules for the proposed CGSA accurately reflect all the changes requested by the Company in this filing. Exhibit CMB-2 provides the existing rate schedules in redline format to identify the changes the Company proposes for the

[5] The Company proposes a new PIT and PIT-Rider for the City of Beaumont and the incorporated and environs areas of the GCSA. The PIT and PIT-Rider are currently in effect in the incorporated and environs areas of the CTSA.

proposed consolidated CGSA. Exhibit CMB-3 contains redlined tariffs for the stand-alone CTSA, stand-alone GCSA and City of Beaumont.

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, GUD No. 10526, for the incorporated and environs of the CTSA, and merged applicability for the GCSA and Beaumont, Texas. Next, the tariffs and rate schedules approved in recent rate cases, GUD Nos. 10656, 10739 and 10766, were reviewed to identify applicable tariff provisions and language to include in the proposed CGSA tariffs. Should consolidation be approved in this SOI, the overall number of tariffs that must be maintained and administered will be reduced.

Q. PLEASE DESCRIBE THE PROPOSED CGSA GAS SALES RATE SCHEDULES.

A. Rate Schedules 10, 20, 30, 40, 48, 1Z, 2Z, 3Z, 4Z and 4H are based on the existing CTSA gas sales rate schedules and incorporate approved changes from GUD Nos. 10656, 10739 and 10766, with revisions made to:

1. include all CTSA Cities, GCSA Cities and the City of Beaumont in the "Territory" section in the incorporated tariffs and to include all CTSA environs, GCSA environs and Beaumont, Texas environs in the "Territory" section in the environs tariffs;
2. add a section to the residential tariffs, Rate Schedules 10 and IZ, providing details of the proposed rate options for customers;

3. add a reference to the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider, under "Other Adjustments;"
4. add a reference to the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, under "Other Adjustments;"
5. add a reference to the Natural Event Response Rider, Rate Schedule NER, under "Other Adjustments;"
6. add residential builders to the "Applicability" section in Rate Schedules 10 and 1Z; and

Additional material differences between the proposed CGSA gas sales tariffs and the gas sales tariffs currently in effect for the City of Beaumont and the GCSA incorporated and environs areas are the:

1. addition of the Pipeline Integrity Testing Rider, Rate Schedule PIT, under "Other Adjustments;
2. addition of the Public Schools Space Heating Service, Rate Schedules 48 and 4H;
3. addition of the Compressed Natural Gas Service, Rate Schedules CNG-1 and CNG-1-ENV;
4. addition of the Electrical Cogeneration Service, Rate Schedules C-1 and C-1-ENV;
5. removal of the curtailment language in the "Conditions" section of the Industrial tariff, Rate Schedules 30 and 3Z, because these provisions are contained in the Company's curtailment plan on file with the Commission; and

6. removal of the unmetered service language in the "Conditions" section of the incorporated and environs GCSA and Beaumont Commercial and Public Authority tariffs, Rate Schedules 20, 2Z, 40 and 4Z, because these provisions are contained in the Company's proposed Unmetered Gas Light Service tariffs, Rate Schedules 70 and 7Z.

The proposed gas sales rates are consistent with the recommendations of Company witness Paul H. Raab.

Q. PLEASE EXPLAIN THE TARIFF REVISION TO OFFER RESIDENTIAL CUSTOMERS TWO RATE OPTIONS.

A. As discussed by Mr. Raab, the Company proposes a residential rate design that includes an A Rate and a B Rate to be assigned to residential customers depending upon customer usage. The revisions to Rate Schedules 10 and 1Z reflect the rate options consistent with 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 No. 10739.

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. Company witness Janet L. Buchanan discusses the revenue adjustment related to this proposed tariff change.

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 CTSA tariffs with revisions made to:

1. include all CTSA Cities, GCSA Cities and the City of Beaumont in the “Territory” section in the incorporated tariff, Rate Schedule C-1, and to include all CTSA environs, GCSA environs and Beaumont, Texas environs in the “Territory” section in the environs tariff, Rate Schedule C-1-ENV;
2. add a reference to the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider, under “Other Adjustments;”
3. add a reference to the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, under “Other Adjustments;” and
4. add a reference to the Natural Event Response Rider, Rate Schedule NER, under “Other Adjustments.”

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.

A. Proposed Rate Schedules CNG-1 and CNG-1-ENV are based on the existing CTSA tariffs with revisions made to:

1. include all CTSA, GCSA Cities and the City of Beaumont in the "Territory" section in the incorporated tariff, Rate Schedule CNG-1, and to include all CTSA, GCSA, and Beaumont, Texas environs areas in the environs tariff, Rate Schedule CNG-1-ENV;
2. add a reference to the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider, under "Other Adjustments;"
3. add a reference to the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, under "Other Adjustments;"
4. add a reference to the Natural Event Response Rider, Rate Schedule NER, under "Other Adjustments;" and
5. clarify the reference and availability of the Average Payment Plan/Average Bill Calculation Plan (ABC/APP Plan) under "Conditions."

Q. PLEASE DESCRIBE THE PROPOSED CGSA TRANSPORTATION SERVICE TARIFFS.

A. Proposed Rate Schedules T-1 and T-1-ENV are based on the existing CTSA transportation rate schedules, while incorporating approved changes from GUD Nos. 10656 and 10739, with revisions made to:

1. include all CTSA, GCSA Cities and the City of Beaumont in the "Availability" section in the incorporated tariff and to include all CTSA, GCSA, and Beaumont, Texas environs areas in the environs tariff;
2. add a reference to the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider, under "Additional Charges;"
3. add a reference to the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, under "Additional Charges;" and
4. add a reference to the Natural Event Response Rider, Rate Schedule NER, under "Additional Charges."

Additional material differences between the proposed CGSA transportation tariffs and the tariffs currently in effect for the City of Beaumont and the GCSA incorporated and environs areas are the addition of the:

1. Pipeline Integrity Testing Rider, Rate Schedule PIT, under "Additional Charges;"
2. Public Schools Space Heating service rate;
3. Compressed Natural Gas service rate; and
4. Electrical Cogeneration service rate.

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 and 10739 with revisions to include definitions for commercial, electrical cogeneration, and industrial service under "Definitions" to provide clarity and match the terminology in the proposed CGSA Rules of Service.

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

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

1. include all CTSA, GCSA Cities and the City of Beaumont in the "Applicability" section in the incorporated tariff and to include all CTSA, GCSA, and Beaumont, Texas environs areas in the environs tariff;
2. add clarifying language to section B.7 regarding lost and unaccounted for gas to match section B.5; and
3. add clarifying language to section B.8 in the incorporated tariff and revise section B.3 in the environs tariff to make consistent with recently approved cost of gas clauses in GUD Nos. 10656, 10739, and 10766.

The proposed cost of gas clauses require the following additional revisions compared to those currently in effect for the City of Beaumont and the incorporated and environs customers in the GCSA:

1. revise sections B.3, B.5, B.7, and H.4 in the incorporated cost of gas clause to include the use of financial instruments; and
2. revise sections B, D, E, G, and H to make the language consistent with the cost of gas clauses in the existing CTSA.

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.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RULES OF SERVICE FOR THE CGSA.

A. The Company developed proposed Rules of Service for the CGSA based on the existing CTSA incorporated and environs Rules of Service, which were updated and approved in 2016. 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. The proposed Rules of Service have also been revised to reflect revisions approved in GUD Nos. 10656, 10739, and 10766. Material differences between the proposed CGSA Rules of Service and existing CTSA, GCSA and City of Beaumont Rules of Service include:

1. Including the incorporated and environs areas of the CTSA, GCSA and Beaumont in § 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 and 10766, 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 CGSA tariffs;

3. Revisions to § 4.5 to better reflect the current course of action customers can take to obtain copies of their tariffs and rate schedules;
4. Revisions to § 4.6 to clarify how and when the Company provides general information to new customers;
5. Revisions to § 7.1 to make advance contribution in aid of construction from an applicant of new service discretionary;
6. Revision to § 7.4 and § 15.8 to clarify that there is no charge to the customer when Company personnel inspect or perform tests on new installations or appliances prior to initiation of service;
7. Addition of § 10.6 which specifies that when a franchise agreement may be in conflict with the terms and conditions of Section § 10, Security Deposits, the franchise agreement terms apply;
8. Revisions to the table in § 11.1 to include the City of Beaumont and the Gulf Coast Cities’ atmospheric and standard serving pressures;
9. Revision to § 12.2 to establish consistency across the Rules of Service regarding a customer’s obligations to grant premise and meter access to Company personnel;
10. Revisions to § 13.7 to clarify payment options administered by contracted vendors;

11. Addition of § 13.8, Deferred Payment Plans, to provide terms and conditions of deferred payment plans that may be offered by the Company to customers consistent with Commission Rule § 7.45(2)(D);
12. Addition of § 17.3 which relates to the suspension of gas utility service disconnection during an extreme weather emergency consistent with Commission Rule § 7.46, and the Company proposes to withdraw the existing CTSA, GCSA and Beaumont environs Rules of Service addendum;
13. Revisions to § 20 to update the language to better reflect current plan descriptions; and
14. Revisions to § 21, Fees and Deposits, to establish greater consistency for service fees and deposits among the Company's service areas.

The Company proposes to withdraw the existing CTSA, GCSA, and Beaumont environs Rules of Service addendum waiving the deposit requirement for victims of family violence because the provision is now included in § 5.5 of the proposed Rules of Service.

Q. WHAT REVISIONS HAS THE COMPANY MADE TO ITS SERVICE FEES AND DEPOSITS AS REFLECTED IN SECTION 21 OF THE PROPOSED RULES OF SERVICE?

A. Exhibit CMB-4 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 and 10766. 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. Buchanan sponsors.

Q. HOW HAS THE COMPANY REVISED THE WEATHER NORMALIZATION CLAUSE FOR THE PROPOSED CGSA?

A. Existing Rate Schedule WNA provides a mechanism whereby incorporated and environs customer bills are adjusted up or down each billing cycle to reflect differences in actual weather compared to normal weather, as defined in the rate case and discussed in the testimony of Ms. Buchanan. Revisions have been made to Rate Schedule WNA to:

1. add the incorporated and environs GCSA and Beaumont customers to the applicability section; and
2. reflect updated weather factors for each class consistent with Ms. Buchanan's weather normalization calculation in this case.

Q. PLEASE DESCRIBE RATE SCHEDULE EDIT-RIDER FOR THE FLOW BACK OF EXCESS DEFERRED FEDERAL INCOME TAXES.

A. Proposed Rate Schedule EDIT-Rider provides a mechanism for the flow back to customers of the annual amortization of EDIT, via an annual one-time bill credit, as described in the testimony of Company witness Stacey L. McTaggart. Rate Schedule EDIT-Rider would be in effect until the Company has completed the flow back of the EDIT balance to customers.

Q. PLEASE DESCRIBE RATE SCHEDULES PIT AND PIT-RIDER 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, and 10739, as described in the testimony of Ms. McTaggart. 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 CMB-5.

Q. PLEASE DESCRIBE THE PROPOSED HARV-RIDER TARIFF.

A. Proposed Rate Schedule HARV-Rider provides a mechanism for the recovery of losses incurred by the Company as a direct result of Hurricane Harvey and not recoverable from any other source, as described in the testimony of Ms. McTaggart.

Q. PLEASE DESCRIBE THE PROPOSED RATE SCHEDULES NATURAL EVENT RESPONSE (NER) AND NER-RIDER.

A. Proposed Rate Schedule NER and NER-Rider was modeled after the structure of the PIT tariff previously approved by the Commission in GUD Nos. 9988, 10506, 10526, 10656, and 10739. It provides a mechanism for the deferral and recovery request of the Company's costs associated with the operation and maintenance expenses resulting from natural events, as described in the testimony of Ms. McTaggart.

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 all rate case expenses determined to be reasonable, as described in the testimony of Ms. McTaggart.

Q. ARE THERE ANY ADDITIONAL COMPANY TARIFFS YOU WISH TO ADDRESS?

A. Yes. The Company proposes no change 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," for the GCSA.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Current and Proposed Rates

Customer Class		Current Rates				Proposed Rates
Residential		CTSA Incorporated and Environs Rates (ab)	GCSA Incorporated Rates (c)	GCSA Environs Rates (d)	City of Beaumont Rates	CGSA Proposed Rates
Customer Charge		$18.81	$12.42	$14.17	$12.10	
Volumetric	All Usage	$0.12061	$0.45616	$0.40680	$0.45616	
Rate A Customer Charge						$14.00
Rate A Volumetric	All Usage					$0.55702
Rate B Customer Charge						$27.58
Rate B Volumetric	All Usage					$0.10435
Commercial						
Customer Charge		$53.33	$51.11	$59.92	$49.49	$53.33
Volumetric	All Usage	$0.11614				$0.12678
	First 250		$0.22140	$0.20185	$0.22140	
	Over 250		$0.19380	$0.17425	$0.19380	
Commercial Transportation						
Customer Charge		$265.33	$297.11	$305.92	$295.49	$265.33
Volumetric	All Usage	$0.11614				$0.12678
	First 250		$0.22140	$0.20185	$0.22140	
	Over 250		$0.19380	$0.17425	$0.19380	
Industrial						
Customer Charge		$320.96	$153.41	$242.79	$153.41	$320.96
Volumetric	All Usage	$0.10273				$0.12703
	First 250		$0.40060	$0.37808	$0.40060	
	Over 250		$0.37480	$0.35228	$0.37480	
Industrial Transportation						
Customer Charge		$520.96	$249.73	$432.79	$217.42	$520.96
Volumetric	All Usage	$0.10273				$0.12703
	First 250	N/A	$0.40060	$0.37808	$0.40060	
	Over 250	N/A	$0.37480	$0.35228	$0.37480	
Public Authority						
Customer Charge		$81.70	$106.10	$117.78	$103.95	$81.70
Volumetric	All Usage	$0.11541				$0.12551
	First 250		$0.15672	$0.13587	$0.15672	
	Over 250		$0.13092	$0.11007	$0.13092	
Public Authority Transportation						
Customer Charge		$104.70	$302.36	$307.78	$302.36	$104.70
Volumetric	All Usage	$0.11541				$0.12551
	First 250		$0.15672	$0.13587	$0.15672	
	Over 250		$0.13092	$0.11007	$0.13092	
Public Schools Space Heating						
Customer Charge		$134.70	N/A	N/A	N/A	$134.70
Volumetric	All Usage	$0.10012	N/A	N/A	N/A	$0.10012
Public Schools Space Heating Transportation						
Customer Charge		$234.70	N/A	N/A	N/A	$234.70
Volumetric	All Usage	$0.10012	N/A	N/A	N/A	$0.10012
Compressed Natural Gas						
Customer Charge		$192.63	N/A	N/A	N/A	$192.63
Volumetric	All Usage	$0.06684	N/A	N/A	N/A	$0.06684
Compressed Natural Gas Transportation						
Customer Charge		$217.63	N/A	N/A	N/A	$217.63
Volumetric	All Usage	$0.06684	N/A	N/A	N/A	$0.06684
Electrical Cogeneration						
Customer Charge		$104.70	N/A	N/A	N/A	$104.70
Volumetric	All Usage		N/A	N/A	N/A	
	First 5000	$0.07720	N/A	N/A	N/A	$0.07720
	Next 35000	$0.06850	N/A	N/A	N/A	$0.06850
	Next 60000	$0.05524	N/A	N/A	N/A	$0.05524
	Over 100000	$0.04016	N/A	N/A	N/A	$0.04016
Electrical Cogeneration Transportation						
Customer Charge		$104.70	N/A	N/A	N/A	$104.70
Volumetric	All Usage		N/A	N/A	N/A	
	First 5000	$0.07720	N/A	N/A	N/A	$0.07720
	Next 35000	$0.06850	N/A	N/A	N/A	$0.06850
	Next 60000	$0.05524	N/A	N/A	N/A	$0.05524
	Over 100000	$0.04016	N/A	N/A	N/A	$0.04016

a Central Texas Incorporated includes: Austin, Bee Cave, Cedar Park, Cuero, Dripping Springs, Gonzales, Kyle, Lakeway, Lockhart, Luling, Nixon, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas

b Central Texas Environs includes: the unincorporated areas of Austin, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Gonzales, Kyle, Lakeway, Lockhart, Luling, Nixon, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas

c Gulf Coast Incorporated includes: Bayou Vista, Galveston, Groves, Jamaica Beach, Nederland, Port Arthur, and Port Neches, Texas

d Gulf Coast Environs includes: the unincorporated areas of Bayou Vista, Galveston, Groves, Jamaica Beach, Nederland, Port Arthur, and Port Neches, Texas

Customer Class		Current CTSA Rates (ab)	CGSA Proposed Rates
Residential			
Customer Charge		$18.81	
Volumetric	All Usage	$0.12061	
Rate A Customer Charge			$14.00
Rate A Volumetric	All Usage		$0.55702
Rate B Customer Charge			$27.58
Rate B Volumetric	All Usage		$0.10435
Commercial			
Customer Charge		$53.33	$53.33
Volumetric	All Usage	$0.11614	$0.12678
Commercial Transportation			
Customer Charge		$265.33	$265.33
Volumetric	All Usage	$0.11614	$0.12678
Industrial			
Customer Charge		$320.96	$320.96
Volumetric	All Usage	$0.10273	$0.12703
Industrial Transportation			
Customer Charge		$520.96	$520.96
Volumetric	All Usage	$0.10273	$0.12703
Public Authority			
Customer Charge		$81.70	$81.70
Volumetric	All Usage	$0.11541	$0.12551
Public Authority Transportation			
Customer Charge		$104.70	$104.70
Volumetric	All Usage	$0.11541	$0.12551
Public Schools Space Heating			
Customer Charge		$134.70	$134.70
Volumetric	All Usage	$0.10012	$0.10012
Public Schools Space Heating Transportation			
Customer Charge		$234.70	$234.70
Volumetric	All Usage	$0.10012	$0.10012
Compressed Natural Gas			
Customer Charge		$192.63	$192.63
Volumetric	All Usage	$0.06684	$0.06684
Compressed Natural Gas Transportation			
Customer Charge		$217.63	$217.63
Volumetric	All Usage	$0.06684	$0.06684
Electrical Cogeneration			
Customer Charge		$104.70	$104.70
Volumetric	All Usage		
	First 5000	$0.07720	$0.07720
	Next 35000	$0.06850	$0.06850
	Next 60000	$0.05524	$0.05524
	Over 100000	$0.04016	$0.04016
Electrical Cogeneration Transportation			
Customer Charge		$104.70	$104.70
Volumetric	All Usage		
	First 5000	$0.07720	$0.07720
	Next 35000	$0.06850	$0.06850
	Next 60000	$0.05524	$0.05524
	Over 100000	$0.04016	$0.04016

a Central Texas Incorporated includes: Austin, Bee Cave, Cedar Park, Cuero, Dripping Springs, Gonzales, Kyle, Lakeway, Lockhart, Luling, Nixon, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas

b Central Texas Environs includes: the unincorporated areas of Austin, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Gonzales, Kyle, Lakeway, Lockhart, Luling, Nixon, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas

Customer Class		Current Incorporated GCSA Rates (c)	CGSA Proposed Rates
Residential			
Customer Charge		$12.42	
Volumetric	All Usage	$0.45616	
Rate A Customer Charge			$14.00
Rate A Volumetric	All Usage		$0.55702
Rate B Customer Charge			$27.58
Rate B Volumetric	All Usage		$0.10435
Commercial			
Customer Charge		$51.11	$53.33
Volumetric	All Usage		$0.12678
	First 250	$0.22140	
	Over 250	$0.19380	
Commercial Transportation			
Customer Charge		$297.11	$265.33
Volumetric	All Usage		$0.12678
	First 250	$0.22140	
	Over 250	$0.19380	
Industrial			
Customer Charge		$153.41	$320.96
Volumetric	All Usage		$0.12703
	First 250	$0.40060	
	Over 250	$0.37480	
Industrial Transportation			
Customer Charge		$249.73	$520.96
Volumetric	All Usage		$0.12703
	First 250	$0.40060	
	Over 250	$0.37480	
Public Authority			
Customer Charge		$106.10	$81.70
Volumetric	All Usage		$0.12551
	First 250	$0.15672	
	Over 250	$0.13092	
Public Authority Transportation			
Customer Charge		$302.36	$104.70
Volumetric	All Usage		$0.12551
	First 250	$0.15672	
	Over 250	$0.13092	
Public Schools Space Heating			
Customer Charge		N/A	$134.70
Volumetric	All Usage	N/A	$0.10012
Public Schools Space Heating Transportation			
Customer Charge		N/A	$234.70
Volumetric	All Usage	N/A	$0.10012
Compressed Natural Gas			
Customer Charge		N/A	$192.63
Volumetric	All Usage	N/A	$0.06684
Compressed Natural Gas Transportation			
Customer Charge		N/A	$217.63
Volumetric	All Usage	N/A	$0.06684
Electrical Cogeneration			
Customer Charge		N/A	$104.70
Volumetric	All Usage	N/A	
	First 5000	N/A	$0.07720
	Next 35000	N/A	$0.06850
	Next 60000	N/A	$0.05524
	Over 100000	N/A	$0.04016
Electrical Cogeneration Transportation			
Customer Charge		N/A	$104.70
Volumetric	All Usage	N/A	
	First 5000	N/A	$0.07720
	Next 35000	N/A	$0.06850
	Next 60000	N/A	$0.05524
	Over 100000	N/A	$0.04016

c Gulf Coast Incorporated includes: Bayou Vista, Galveston, Groves, Jamaica Beach, Nederland, Port Arthur, and Port Neches, Texas

Customer Class		Current Environs GCSA Rates (d)	CGSA Proposed Rates
Residential			
Customer Charge		$14.17	
Volumetric	All Usage	$0.40680	
Rate A Customer Charge			$14.00
Rate A Volumetric	All Usage		$0.55702
Rate B Customer Charge			$27.58
Rate B Volumetric	All Usage		$0.10435
Commercial			
Customer Charge		$59.92	$53.33
Volumetric	All Usage		$0.12678
	First 250	$0.20185	
	Over 250	$0.17425	
Commercial Transportation			
Customer Charge		$305.92	$265.33
Volumetric	All Usage		$0.12678
	First 250	$0.20185	
	Over 250	$0.17425	
Industrial			
Customer Charge		$242.79	$320.96
Volumetric	All Usage		$0.12703
	First 250	$0.37808	
	Over 250	$0.35228	
Industrial Transportation			
Customer Charge		$432.79	$520.96
Volumetric	All Usage		$0.12703
	First 250	$0.37808	
	Over 250	$0.35228	
Public Authority			
Customer Charge		$117.78	$81.70
Volumetric	All Usage		$0.12551
	First 250	$0.13587	
	Over 250	$0.11007	
Public Authority Transportation			
Customer Charge		$307.78	$104.70
Volumetric	All Usage		$0.12551
	First 250	$0.13587	
	Over 250	$0.11007	
Public Schools Space Heating			
Customer Charge		N/A	$134.70
Volumetric	All Usage	N/A	$0.10012
Public Schools Space Heating Transportation			
Customer Charge		N/A	$234.70
Volumetric	All Usage	N/A	$0.10012
Compressed Natural Gas			
Customer Charge		N/A	$192.63
Volumetric	All Usage	N/A	$0.06684
Compressed Natural Gas Transportation			
Customer Charge		N/A	$217.63
Volumetric	All Usage	N/A	$0.06684
Electrical Cogeneration			
Customer Charge		N/A	$104.70
Volumetric	All Usage	N/A	
	First 5000	N/A	$0.07720
	Next 35000	N/A	$0.06850
	Next 60000	N/A	$0.05524
	Over 100000	N/A	$0.04016
Electrical Cogeneration Transportation			
Customer Charge		N/A	$104.70
Volumetric	All Usage	N/A	
	First 5000	N/A	$0.07720
	Next 35000	N/A	$0.06850
	Next 60000	N/A	$0.05524
	Over 100000	N/A	$0.04016

d Gulf Coast Incorporated includes: Bayou Vista, Galveston, Groves, Jamaica Beach, Nederland, Port Arthur, and Port Neches, Texas

Customer Class		Current City of Beaumont Rates	CGSA Proposed Rates
Residential			
Customer Charge		$12.10	
Volumetric	All Usage	$0.45616	
Rate A Customer Charge			$14.00
Rate A Volumetric	All Usage		$0.55702
Rate B Customer Charge			$27.58
Rate B Volumetric	All Usage		$0.10435
Commercial			
Customer Charge		$49.49	$53.33
Volumetric	All Usage		$0.12678
	First 250	$0.22140	
	Over 250	$0.19380	
Commercial Transportation			
Customer Charge		$295.49	$265.33
Volumetric	All Usage		$0.12678
	First 250	$0.22140	
	Over 250	$0.19380	
Industrial			
Customer Charge		$153.41	$320.96
Volumetric	All Usage		$0.12703
	First 250	$0.40060	
	Over 250	$0.37480	
Industrial Transportation			
Customer Charge		$217.42	$520.96
Volumetric	All Usage		$0.12703
	First 250	$0.40060	
	Over 250	$0.37480	
Public Authority			
Customer Charge		$103.95	$81.70
Volumetric	All Usage		$0.12551
	First 250	$0.15672	
	Over 250	$0.13092	
Public Authority Transportation			
Customer Charge		$302.36	$104.70
Volumetric	All Usage		$0.12551
	First 250	$0.15672	
	Over 250	$0.13092	
Public Schools Space Heating			
Customer Charge		N/A	$134.70
Volumetric	All Usage	N/A	$0.10012
Public Schools Space Heating Transportation			
Customer Charge		N/A	$234.70
Volumetric	All Usage	N/A	$0.10012
Compressed Natural Gas			
Customer Charge		N/A	$192.63
Volumetric	All Usage	N/A	$0.06684
Compressed Natural Gas Transportation			
Customer Charge		N/A	$217.63
Volumetric	All Usage	N/A	$0.06684
Electrical Cogeneration			
Customer Charge		N/A	$104.70
Volumetric	All Usage	N/A	
	First 5000	N/A	$0.07720
	Next 35000	N/A	$0.06850
	Next 60000	N/A	$0.05524
	Over 100000	N/A	$0.04016
Electrical Cogeneration Transportation			
Customer Charge		N/A	$104.70
Volumetric	All Usage	N/A	
	First 5000	N/A	$0.07720
	Next 35000	N/A	$0.06850
	Next 60000	N/A	$0.05524
	Over 100000	N/A	$0.04016

Exhibits CMB-2 through CMB-3 are Voluminous and will be provided electronically.

Current and Proposed Service Fees

	Central Texas Service Area		Gulf Coast Service Area		City of Beaumont	
Fee or Deposit	Current Fee	Proposed Fee	Current Fee	Proposed Fee	Current Fee	Proposed Fee
Connect	$35.00	No Change	$35.00	No Change	$35.00	No Change
Reconnect	$35.00	No Change	$35.00	No Change	$35.00	No Change
Read-In	$10.00	$15.00	$10.00	$15.00	$10.00	$15.00
Special Handling	$6.00	$15.00	$6.00	$15.00	$6.00	$15.00
Expedited Service/Overtime/After Hours (Customer Request)	$67.50	$60.00	$67.50	$60.00	$67.50	$60.00
Regular Labor Rate	$45.00	No Change	$45.00	No Change	$45.00	No Change
No Access Fee (Door Tag)	$10.00	$15.00	$10.00	$15.00	$10.00	$15.00
Customer Requested Meter Test:						
Positive Displacement Meters						
Meter Test Up to 1500 CFH (All Classes)	$80.00	$150.00	$80.00	$150.00	$80.00	$150.00
Meter Test Over 1500 CFH (All Classes)	$100.00	$200.00	$100.00	$200.00	$100.00	$200.00
Orifice Meters (All Sizes)	$100.00	$200.00	$100.00	$200.00	$100.00	$200.00
Payment Re-processing Fee (Returned Check Fee)	$25.00	No Change	$25.00	No Change	$25.00	No Change
Collection Fee (All Classes)	$12.00	$15.00	$12.00	$15.00	$12.00	$15.00
Special Read	$10.00	$15.00	$10.00	$15.00	$10.00	$15.00
Meter Exchange without ERT (Customer Request)	$100.00	Discontinue	$100.00	Discontinue	$100.00	Discontinue
Meter Exchange with ERT (Customer Request)	$150.00	No Change	$150.00	No Change	$150.00	No Change
Unauthorized Consumption	$20.00 plus expenses	$30.00 plus expenses	$20.00 plus expenses	$30.00 plus expenses	$20.00 plus expenses	$30.00 plus expenses
Meter Removal Fee	$50.00	$25.00	$50.00	$25.00	$50.00	$25.00
Account Research Fee	$25.00/hr	$20.00/hr	$25.00/hr	$20.00/hr	$25.00/hr	$20.00/hr
Meter Tampering (Residential)	$100.00	$150.00	$100.00	$150.00	$100.00	$150.00
Police Escort Fee:						
Regular Rate	$52.00	Actual Cost	Actual Cost	No Change	Actual Cost	No Change
Overtime Rate	$132.60	Actual Cost	Actual Cost	No Change	Actual Cost	No Change
Holiday Rate	$158.60	Actual Cost	Actual Cost	No Change	Actual Cost	No Change
Excess Flow Valve Installation Fee	$400.00	No Change	$400.00	No Change	$400.00	No Change
Advances	Estimated Cost	No Change	Estimated Cost	No Change	Estimated Cost	No Change
Customer Deposit:						
Residential Minimum [1]	$75.00	No Change	$75.00	No Change	$75.00	No Change
Non-Residential Minimum [1]	$250.00	No Change	$250.00	No Change	$250.00	No Change

[1] One sixth (1/6) of the estimated annual billings for services rendered - stated amounts are the minimums.

PUBLIC NOTICE
_____ CGSA 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 Central-Gulf Service Area incorporated and environs areas of Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas and the environs of Buda, 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 CGSA is set forth in the table below:

Rate Schedule	**PIT Rate per Ccf**	**Average Monthly Bill Impact**	**Number of Customers**
Residential			
Commercial			
Public Authority			
Industrial			
Public Schools Space Heating			
Compressed Natural Gas			
Electrical Cogeneration			
Standard Transportation			

Persons with 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 5613 Avenue F in Austin, Texas, 4201 39th Street in Port Arthur, Texas, or 402 33rd Street in Galveston, Texas, or on the Company's website at https://www.texasgasservice.com/newsletters-and-notices/rate-notices.

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF CHRISTY BELL

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

1. "My name is Christy Bell. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Rates Analyst I for Texas Gas Service Company, a division of ONE Gas, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Christy Bell
Christy Bell

SUBSCRIBED AND SWORN TO BEFORE ME by the said Christy Bell on this 4th day of December, 2019.

MARY L PENA
NOTARY PUBLIC
ID# 11652311
State of Texas
Comm. Exp. 05-13-2023

NOTARY PUBLIC
STATE OF TEXAS

Mary L. Pena
Notary Public in and for the State of Texas

PUBLIC NOTICE OF PROPOSED RATE CHANGE
NATURAL GAS UTILITY RATES

On December 20, 2019, Texas Gas Service Company, a Division of ONE Gas, Inc. (“TGS” or “Company”), filed a Statement of Intent to Change Rates (“Statement of Intent”) with the Railroad Commission of Texas and with the Cities of Austin, Bee Cave, Cedar Park, Cuero, Dripping Springs, Gonzales, Kyle, Lakeway, Lockhart, Luling, Rollingwood, Shiner, Sunset Valley, Nixon, West Lake Hills, Yoakum, Bayou Vista, Galveston, Groves, Jamaica Beach, Nederland, Port Arthur and Port Neches, Texas and the City of Beaumont for the gas utility rates charged by the Company to customers within the Central Texas Service Area (“CTSA”), the Gulf Coast Service Area (“GCSA”) and the City of Beaumont. The proposed change in rates will affect all residential, commercial, commercial transportation, industrial, industrial transportation, public authority, public authority transportation, compressed natural gas, compressed natural gas transportation, electrical cogeneration transportation, public school space heating and public school space heating transportation customers within the incorporated cities and unincorporated areas of the CTSA and GCSA and the City of Beaumont. The proposed effective date of the requested rate changes is February 6, 2020.

In addition to changing rates, TGS proposes to consolidate the CTSA, the GCSA and the City of Beaumont into one new service area called the Central-Gulf Service Area ("CGSA"). 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 CGSA on a combined basis. The proposed rates and tariffs are expected to increase the Company’s annual system-wide revenues within the proposed CGSA by approximately $17 million or 9.43% including gas cost or 15.64% 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 CGSA by more than two and one-half percent. The proposed change in rates will not become effective until similar changes have become effective within the nearest incorporated city.

The Company proposes to implement the rates included in Table 1 below:

TABLE 1 – Proposed Rate Changes for Incorporated and Unincorporated/Environs Customers

	Incorporated and Unincorporated/Environs Current Rates					
Customer Class	**CTSA Incorporated Rates**	**CTSA Environs Rates**	**GCSA Incorporated Rates**	**GCSA Environs Rates**	**City of Beaumont Rates**	**Proposed CGSA Rates**
Residential (No. of Customers Affected)	229,420	22,251	41,183	1,142	1	
Customer Charge	$18.81	$18.81	$12.42	$14.17	$12.10	$14.00 (Option A) $27.58 (Option B)
Volumetric Charge (per Ccf)	$0.12064	$0.12064	$0.45616	$0.40680	$0.45616	$0.55702 (Option A) $0.10435 (Option B)
Commercial (No. of Customers Affected)	11,658	650	1,782	28	1	
Customer Charge	$53.33	$53.33	$51.11	$59.92	$49.49	$53.33

Customer Class	CTSA Incorporated Rates	CTSA Environs Rates	GCSA Incorporated Rates	GCSA Environs Rates	City of Beaumont Rates	Proposed CGSA Rates
Volumetric Charge (per Ccf)	$0.11614	$0.11614	$0.22140 (First 250 Ccf) ------- $0.19380 (All Over 250 Ccf)	$0.20185 (First 250 Ccf) ------- $0.17425 (All Over 250 Ccf)	$0.22140 (First 250 Ccf) ------- $0.19380 (All Over 250 Ccf)	$0.12678
Commercial Transportation (No. of Customers Affected)	327	9	30	No Customers	No Customers	
Customer Charge	$265.33	$265.33	$297.11	$305.92	$295.49	$265.33
Volumetric Charge (per Ccf)	$0.11614	$0.11614	$0.22140 (First 250 Ccf) ------- $0.19380 (All Over 250 Ccf)	$0.20185 (First 250 Ccf) ------- $0.17425 (All Over 250 Ccf)	$0.22140 (First 250 Ccf) ------- $0.19380 (All Over 250 Ccf)	$0.12678
Industrial (No. of Customers Affected)	21	No Customers	No Customers	No Customers	No Customers	
Customer Charge	$320.96	$320.96	$153.41	$242.79	$153.41	$320.96
Volumetric Charge (per Ccf)	$0.10273	$0.10273	$0.40060 (First 250 Ccf) ------- $0.37480 (All Over 250 Ccf)	$0.37808 (First 250 Ccf) ------- $0.35228 (All Over 250 Ccf)	$0.40060 (First 250 Ccf) ------- $0.37480 (All Over 250 Ccf)	$0.12703
Industrial Transportation (No. of Customers Affected)	32	1	4	No Customers	No Customers	
Customer Charge	$520.96	$520.96	$249.73	$432.79	$217.42	$520.96
Volumetric Charge (per Ccf)	$0.10273	$0.10273	$0.40060 (First 250 Ccf) ------- $0.37480 (All Over 250 Ccf)	$0.37808 (First 250 Ccf) ------- $0.35228 (All Over 250 Ccf)	$0.40060 (First 250 Ccf) ------- $0.37480 (All Over 250 Ccf)	$0.12703
Public Authority (No. of Customers Affected)	519	47	261	4	No Customers	
Customer Charge	$81.70	$81.70	$106.10	$117.78	$103.95	$81.70

Customer Class	**CTSA Incorporated Rates**	**CTSA Environs Rates**	**GCSA Incorporated Rates**	**GCSA Environs Rates**	**City of Beaumont Rates**	**Proposed CGSA Rates**
Volumetric Charge (per Ccf)	$0.11541	$0.11541	$0.15672 (First 250 Ccf) ------- $0.13092 (All Over 250 Ccf)	$0.13587 (First 250 Ccf) ------- $0.11007 (All Over 250 Ccf)	$0.15672 (First 250 Ccf) ------- $0.13092 (All Over 250 Ccf)	$0.12551
Public Authority Transportation (No. of Customers Affected)	384	6	No Customers	No Customers	No Customers	
Customer Charge	$104.70	$104.70	$302.36	$307.78	$302.36	$104.70
Volumetric Charge (per Ccf)	$0.11541	$0.11541	$0.15672 (First 250 Ccf) ------- $0.13092 (All Over 250 Ccf)	$0.13587 (First 250 Ccf) ------- $0.11007 (All Over 250 Ccf)	$0.15672 (First 250 Ccf) ------- $0.13092 (All Over 250 Ccf)	$0.12551
Electrical Cogeneration (No. of Customers Affected)	No Customers	No Customers	No Customers	No Customers	No Customers	
Customer Charge	$104.70	$104.70	NA	NA	NA	$104.70
Volumetric Charge (per Ccf)	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)	NA	NA	NA	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)
Electrical Cogeneration Transportation (No. of Customers Affected)	1	No Customers	No Customers	No Customers	No Customers	
Customer Charge	$104.70	$104.70	NA	NA	NA	$104.70

Customer Class	CTSA Incorporated Rates	CTSA Environs Rates	GCSA Incorporated Rates	GCSA Environs Rates	City of Beaumont Rates	Proposed CGSA Rates
Volumetric Charge (per Ccf)	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)	NA	NA	NA	$0.07720 (First 5,000 Ccf) ------- $0.06850 (Next 35,000 Ccf) ------- $0.05524 (Next 60,000) ------- $0.04016 (All Over 100,000 Ccf)
Public School Space Heating (No. of Customers Affected)	4	1	No Customers	No Customers	No Customers	
Customer Charge	$134.70	$134.70	NA	NA	NA	$134.70
Volumetric Charge (per Ccf)	$0.10012	$0.10012	NA	NA	NA	$0.10012
Public School Space Heating Transportation (No. of Customers Affected)	80	2	No Customers	No Customers	No Customers	
Customer Charge	$234.70	$234.70	NA	NA	NA	$234.70
Volumetric Charge All Ccf	$0.10012	$0.10012	NA	NA	NA	$0.10012
Compressed Natural Gas (No. of Customers Affected)	3	No Customers	No Customers	No Customers	No Customers	
Customer Charge	$192.63	$192.63	NA	NA	NA	$192.63
Volumetric Charge (per Ccf)	$0.06684	$0.06684	NA	NA	NA	$0.06684
Compressed Natural Gas Transportation (No. of Customers Affected)	3	1	No Customers	No Customers	No Customers	
Customer Charge	$217.63	$217.63	NA	NA	NA	$217.63
Volumetric Charge (per Ccf)	$0.06684	$0.06684	NA	NA	NA	$0.06684

TABLE 2 – Impact on Average Bill

Customer Class (Average Monthly Usage)	Current Average Monthly Bill with Gas Cost	Proposed Average Monthly Bill with Gas Cost	Proposed Monthly Change	Percentage Change with Gas Cost	Percentage Change without Gas Cost
Residential - Rate Option A (CTSA Inc) 18 Ccf	$29.20	$32.33	$3.13	10.7%	14.5%
Residential - Rate Option A (CTSA Env) 18 Ccf	$29.20	$32.33	$3.13	10.7%	14.5%
Residential - Rate Option A (GCSA Inc) 18 Ccf	$29.57	$32.33	$2.76	9.3%	16.4%
Residential - Rate Option A (GCSA Env) 18 Ccf	$30.44	$32.33	$1.89	6.2%	11.8%
Residential - Rate Option A (City of Beaumont) 18 Ccf	$29.25	$32.33	$3.08	10.5%	18.3%
Residential - Rate Option B (CTSA Inc) 45 Ccf	$44.71	$52.99	$8.28	18.5%	33.2%
Residential - Rate Option B (CTSA Env) 45 Ccf	$44.71	$52.99	$8.28	18.5%	33.2%
Residential - Rate Option B (GCSA Inc) 45 Ccf	$55.21	$52.99	$(2.22)	(4.0)%	(1.9)%
Residential - Rate Option B (GCSA Env) 45 Ccf	$54.74	$52.99	$(1.75)	(3.2)%	(0.5)%
Residential - Rate Option B (City of Beaumont) 45 Ccf	$54.89	$52.99	$(1.90)	(3.5)%	(1.0)%
Commercial (CTSA Inc) 263 Ccf	$203.72	$207.89	$4.17	2.0%	3.3%
Commercial (CTSA Env) 263 Ccf	$203.72	$207.89	$4.17	2.0%	3.3%
Commercial (GCSA Inc) 263 Ccf	$239.47	$207.89	$(31.58)	(13.2)%	(20.5)%
Commercial (GCSA Env) 263 Ccf	$243.14	$207.89	$(35.25)	(14.5)%	(23.1)%
Commercial (City of Beaumont) 263 Ccf	$237.85	$207.89	$(29.96)	(12.6)%	(19.3)%
Public Authority (CTSA Inc/Env) 442 Ccf	$334.64	$341.41	$6.77	2.0%	3.4%
Public Authority (GCSA Inc) 442 Ccf	$390.32	$341.41	$(48.91)	(12.5)%	(19.5)%
Public Authority (GCSA Env) 442 Ccf	$392.78	$341.41	$(51.37)	(13.1)%	(20.6)%
Industrial (CTSA Inc/Env) 2,565 Ccf	$1,755.39	$1,831.10	$75.71	4.3%	10.7%
Public Schools Space Heating (Inc/Env) 1,927 Ccf	$1,207.53	$1,217.59	$10.06	0.8%	0.0%
Compressed Natural Gas (CTSA Inc) 17 Ccf	$201.64	$201.73	$0.09	0.0%	0.0%
Commercial Transport (CTSA Inc) 4,616 Ccf	$2,803.50	$2,875.50	$72.00	2.6%	6.1%

Customer Class (Average Monthly Usage)	Current Average Monthly Bill with Gas Cost	Proposed Average Monthly Bill with Gas Cost	Proposed Monthly Change	Percentage Change with Gas Cost	Percentage Change without Gas Cost
Commercial Transport (CTSA Env) 4,616 Ccf	$2,803.50	$2,875.50	$72.00	2.6%	6.1%
Commercial Transport (GCSA Inc) 4,616 Ccf	$3,378.83	$2,875.50	$(503.33)	(14.9)%	(29.0)%
Industrial Transport (CTSA Inc/Env) 14,681 Ccf	$8,397.14	$8,826.68	$429.54	5.1%	17.6%
Industrial Transport (GCSA Inc) 14,681 Ccf	$12,693.43	$8,826.68	$(3,866.75)	(30.5)%	(58.6)%
Public Authority Transport (CTSA Inc/Env) 1,580 Ccf	$972.51	$996.30	$23.79	2.4%	5.6%
Public School Space Heating Transport (CTSA Inc/Env) 1,225 Ccf	$888.51	$894.58	$6.07	0.7%	0.0%
Electrical Cogeneration Transport (CTSA Inc) 323,832 Ccf	$155,654.46	$157,260.17	$1,605.71	1.0%	0.0%
Compressed Natural Gas Transport (CTSA Inc/Env) 28,168 Ccf	$14,318.55	$14,458.22	$139.67	1.0%	0.0%

Table 2 calculations are based on a $0.46 cost of gas and do not include revenue-related taxes and do not include the Conservation Adjustment Clause rate, which is applicable in the incorporated CTSA. Additionally, only classes with customers in the test year are included in Table 2.

The Company also proposes Miscellaneous Service Charges included in Table 3 below.

Table 3 – Miscellaneous Service Charges

Incorporated/Environs	CTSA, GCSA, and the City of Beaumont		
Fee or Deposit	Current Charge	Proposed Charge	Proposed Change
Connect	$35.00	$35.00	$0.00
Reconnect	$35.00	$35.00	$0.00
Special Handling	$6.00	$15.00	$9.00
Expedited Service/ Overtime/ After Hour F	$67.50	$60.00	$(7.50)
No Access Fee	$10.00	$15.00	$5.00
Meter Test up to 1500 CFH[a] (All Classes)	$80.00	$150.00	$70.00
Meter Test Over 1500 CFH (All Classes)	$100.00	$200.00	$100.00
Orifice Meters (All Size)	$100.00	$200.00	$100.00
Payment Re-processing Fee	$25.00	$25.00	$0.00
Collection Fee (All Classes)	$12.00	$15.00	$3.00
Special Read	$10.00	$15.00	$5.00
Meter Exchange without ERT[b]	$100.00	Discontinue	Discontinue
Meter Exchange with ERT	$150.00	$150.00	$0.00
Unauthorized Consumption	20.00 plus expenses	30.00 plus expenses	10.00 plus expenses
Meter Removal Fee	$50.00	$25.00	$(25.00)
Account Research Fee	25.00/hr	20.00/hr	$(5.00)/hr
Meter Tampering (Residential)	$100.00	$150.00	$50.00

Incorporated/Environs	CTSA, GCSA, and the City of Beaumont		
Police Escort (Regular Rate) - CTSA	$52.00	Actual Cost	TBD
Police Escort (Regular Rate) - GCSA/City of Beaumont	Actual Cost	Actual Cost	No Change
Police Escort (Overtime Rate) - CTSA	$132.60	Actual Cost	TBD
Police Escort (Overtime Rate) - GCSA/City of Beaumont	Actual Cost	Actual Cost	No Change
Police Escort (Holiday Rate) - CTSA	$158.60	Actual Cost	TBD
Police Escort (Holiday Rate) - GCSA/City of Beaumont	Actual Cost	Actual Cost	No Change
Excess Flow Valve Installation Fee	$400.00	$400.00	$0.00
Advances	Estimated Cost	Estimated Cost	No Change
Residential Minimum Cust. Deposit	$75.00	$75.00	$0.00
Non-Residential Minimum Cust. Deposit	$250.00	$250.00	$0.00

[a] CFH: Cubic Feet per Hour.
[b] ERT: Electronic Radio Transponder. The Company only exchanges meters with ERT.

The proposed increases in Table 3 reflect a net increase of $277,029 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) a prudence determination for capital investment made in the proposed CGSA through December 31, 2019; (3) a finding from the Commission that ONE Gas' acquisition of ONEOK Transmission Company ("OTC") and its assets is consistent with the public interest under Texas Utilities Code § 102.051; (4) 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 GUD No. 10695 are reasonable and accurate; (5) approval of the form of notice pursuant to the proposed Rate Schedule PIT; and (6) approval to recover the reasonable rate case expenses associated with this filing through a surcharge on rates, as provided by law.

In addition, TGS proposes to withdraw the existing CTSA, GCSA and City of Beaumont tariffs for which TGS is requesting changes. This includes withdrawal of the existing Rules of Service for the CTSA, GCSA and City of Beaumont, and TGS requests approval of Rules of Service applicable to all rate classes within the proposed CGSA. For the requested Rules of Service, TGS proposes (1) including the incorporated and environs areas of the CTSA, GCSA and Beaumont in § 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 and 10766, as well as add a definition for "electrical cogeneration service," while removing the definition for "power generation service" to establish consistency with terminology used across all proposed CGSA tariffs; (3) Revisions to § 4.5 to better reflect the current course of action customers can take to obtain copies of tariffs and rate schedules; (4) revisions to § 4.6 to clarify how and when the Company provides general information to new customers; (5) revisions to § 7.1 to make advance contribution in aid of construction from an applicant of new service discretionary; (6) revisions to § 7.4 and § 15.8 to clarify that there is no charge to the customer when Company personnel inspect or perform tests on new installations or appliances prior to initiation of service; (7) addition of § 10.6, which specifies that when a franchise agreement may be in conflict with the terms and conditions of Section § 10, Security Deposits, the franchise agreement terms apply; (8) revisions to the table in § 11.1 to include the City of Beaumont and the Gulf Coast Cities' atmospheric and standard serving pressures; (9) revisions to § 12.2 to establish consistency across the Rules of Service regarding a customer's obligations to grant premise and meter access to Company personnel; (10) revisions to § 13.7 to clarify payment options administered by contracted vendors; (11) addition of § 13.8, Deferred Payment Plans, to provide terms and conditions of deferred payment plans that may be offered by the Company to customers consistent with Commission Rule § 7.45(2)(D); (12) addition of § 17.3, which relates to the suspension of gas utility service disconnection during an extreme weather emergency consistent with Commission Rule § 7.46, and the Company proposes to withdraw the existing CTSA and GCSA Rules of Service addendum; (13) revisions to § 20 to update the language to better reflect current plan descriptions; and (14) revisions to § 21, Fees and Deposits, to establish greater consistency for service fees and deposits among the Company's service areas.

In addition, TGS requests approval of rate schedules and tariffs applicable to all rate classes within the proposed CGSA that contain the rates reflected in Table 1. TGS also proposes the following new rate schedules for the proposed CGSA: (1) Rate Schedule EDIT-Rider for the flow back to customers of the annual amortization of Excess Deferred Income Taxes, via a one-time bill credit; (2) Rate Schedules PIT and PIT-Rider to recover pipeline integrity testing costs; (3) Rate Schedule HARV-Rider for the recovery of reasonable and necessary expenses TGS incurred to restore service as a direct result of Hurricane Harvey; (4) Rate Schedules NER and NER-Rider to recover future extraordinary operations and maintenance expenses resulting from natural events; and (5) Rate Schedules 70 and 7Z to provide unmetered service to customers using natural gas for gas lighting only. For the proposed CGSA gas sales rate schedules, TGS proposes changes to base rate schedules 10, 20, 30, 40, 48, 1Z, 2Z, 3Z, 4Z and 4H to: (1) to add references to Rate Schedule EDIT-Rider, Rate Schedule HARV-Rider, and Rate Schedule NER-Rider, under "Other Adjustments; (2) add a new residential A/B rate design to Rate Schedules 10 and 1Z that will provide options for customers based on their usage patterns and add residential builders to the "Applicability" sections. Additional material differences between the proposed CGSA gas sales tariffs and the gas sales tariffs currently in effect for the City of Beaumont and the GCSA incorporated and environs areas are the: (1) addition of the Pipeline Integrity Testing Rider, Rate Schedule PIT, under "Other Adjustments; (2) addition of the Public Schools Space Heating Service, Rate Schedules 48 and 4H; (3) addition of the Compressed Natural Gas Service, Rate Schedules CNG-1 and CNG-1-ENV; (4) addition of the Electrical Cogeneration Service, Rate Schedules C-1 and C-1-ENV; (5) removal of the curtailment language in the "Conditions" section of the Industrial tariff, Rate Schedules 30 and 3Z because these provisions are contained in the Company's curtailment plan on file with the Commission; and (6) removal of the unmetered service language in the "Conditions" section of the incorporated and environs GCSA and Beaumont Commercial and Public Authority tariffs, Rate Schedules 20, 2Z, 40 and 4Z, because these provisions are contained in the Company's proposed Unmetered Gas Light Service tariffs, Rate Schedules 70 and 7Z. For the proposed CGSA Transportation service rate schedules, TGS proposes changes to Rate Schedules T-1 and T-1-ENV to: (1) include all CTSA, GCSA Cities and the City of Beaumont in the "Availability" section in the incorporated tariff and to include all CTSA, GCSA, and Beaumont, Texas environs areas in the environs tariff; (2) add a reference to the Rate Schedule EDIT-Rider, Rate Schedule HARV-Rider, and Rate Schedule NER under "Additional Charges;" Additional material differences between the proposed CGSA transportation tariffs and the tariffs currently in effect for the City of Beaumont and the GCSA incorporated and environs areas are the addition of the: (1) Pipeline Integrity Testing Rider, Rate Schedule PIT, under "Additional Charges;" (2) Public Schools Space Heating service rate; (3) Compressed Natural Gas service rate; and (4) Electrical Cogeneration service rate. TGS also proposes Rate Schedule T-TERMS to provide clarity and match the terminology in the proposed CGSA Rules of Service. For the proposed CGSA Cost of Gas Clause tariffs, TGS proposes changes to Rate Schedules 1-INC and 1-ENV to: (1) include all CTSA Cities, GCSA Cities and the City of Beaumont in the "Applicability" section in the incorporated tariff and to include all CTSA, GCSA, and Beaumont, Texas environs areas in the environs tariff; (2) add clarifying language to section B.7 regarding lost and unaccounted for gas to match section B.5; and (3) add clarifying language to section B.8 in the incorporated tariff and revise section B.3 in the environs tariff to make consistent with recently approved cost of gas clauses. The proposed CGSA Cost of Gas Clause tariff also contains: (1) revisions to sections B.3, B.5, B.7, and H.4 in the incorporated cost of gas clause to include the use of financial instruments; and (2) revise sections B, D, E, G, and H to make the language consistent with the cost of gas clauses in the existing CTSA. Existing Rate Schedule WNA provides a mechanism whereby 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. Revisions have been made to Rate Schedule WNA to: (1) add the incorporated and environs GCSA and Beaumont customers to the "Applicability" section; and (2) reflect updated weather factors for each class consistent with the weather normalization calculation in TGS's rate filing. TGS also proposes to withdraw Rate Schedule COSA, "Cost of Service Adjustment Clause," for the GCSA. TGS also requests approval of Rate Schedules RCE and RCE-ENV for recovery of approved rate case expenses related to the TGS's Statement of Intent.

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 5613 Avenue F, Austin, Texas 78751, 402 33rd St., Galveston, Texas 77550 or 4201 39th Street, Port Arthur, Texas 77642, or on the Company's website at https://www.texasgasservice.com/CustomerNotices-Rate_Notices. 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 March 7, 2020. Please reference GUD No. ________. 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, una Division de ONE Gas, Inc., ("TGS" o la "Compañía") de el área del Norte de Texas 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, industriales y de autoridad pública. Las personas que deseen hacer preguntas específicas o recibir más información sobre esta solicitud pueden comunicarse con la Compañía llamando al 1-800-700-2443 o envié un mensaje de correo electrónico a la dirección ODCInformationCenterWebTeam@onegas.com. Cualquier persona afectada puede presentar por escrito comentarios o una protesta sobre el cambio de tarifas propuesto a la Sección de Servicios de la Oficina de la División de Audiencias, Comisión Ferroviaria de Texas, P.O. Box 12967, Austin, Texas 78711-2967, en cualquier momento dentro de los 30 días siguientes a la fecha en que este cambio entraría en vigencia o el 7 de marzo del 2020. Por favor, haga referencia a GUD No. ________. 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 CENTRAL TEXAS SERVICE AREA, THE GULF COAST SERVICE AREA AND THE CITY OF BEAUMONT

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 Central Texas Service Area, the Gulf Coast Service Area and the City of Beaumont, 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 Central Texas Service Area, the Gulf Coast Service Area and the City of Beaumont, 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.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

SUMMARY OF REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
			(a)	(b)	(c)
1	Rate Base	B	$444,578,089	$28,889,947	$473,468,036
2	Rate of Return	E	7.9266%	7.9266%	7.9266%
3	Required Return		$35,239,713	$2,289,977	$37,529,690
4	Cost of Gas	G	75,042,680	(75,042,680)	0
5	Depreciation and Amortization Expense	G	19,139,503	2,542,480	21,681,983
6	Taxes Other Than Income Taxes	G	5,822,174	1,200,847	7,023,021
7	Interest on Customer Deposits	G	117,153	33,639	150,792
8	Transmission and High-Pressure Distribution Expense	G	673,955	298,199	972,153
9	Distribution Expense	G	15,776,036	1,120,379	16,896,414
10	Customer Accounts Expense	G	6,961,766	448,840	7,410,606
11	Administrative and General Expense	G	28,212,839	(1,901,593)	26,311,246
12	Federal Income Tax	F	7,378,482	477,044	7,855,526
13	Revenue Requirement before Gross-up		$194,364,301	($68,532,869)	$125,831,431
14	Test Year Adjusted Revenue	G	178,503,125	(69,498,918)	109,004,207
15	Revenue Deficiency		$15,861,176	$966,049	$16,827,224
	Gross-up for Revenue Related Expenses:	Factors:			
16	Uncollectible Expense	0.0053730			
17	Texas Franchise Tax	0.0075000			
18	Gross-Up Percentage	0.0128730	206,844	12,598	219,442
19	Total Revenue Deficiency		$16,068,019	$978,647	$17,046,666
20	Total Revenue Requirement (Line 13 + Line 18)		$194,571,144	($68,520,271)	$126,050,873

WKP A.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROOF OF REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	AMOUNT (a)	AMOUNT (b)
1	Total Revenue Requirement		$126,050,873
	Less:		
2	Depreciation	$21,681,983	
3	Taxes	7,023,021	
4	Interest on Deposits	150,792	
5	Transmission Expense	972,153	
6	Distribution Expense	16,896,414	
7	Customer Accounting	7,410,606	
8	Administrative and General Expense	26,311,246	
9	Gross-Up Expenses	219,442	
10	Total Operating Expense	$80,665,657	80,665,657
11	**Less** Interest on Long-Term Debt		8,118,693
12	Taxable Income	$37,266,523	$37,266,523
13	Add back disallowed parking expense		140,742
14	Tax Rate	21%	
15	Income Taxes	$7,855,526	
16	**Less** Tax Adjustments	0	
17	Net Income Tax	$7,855,526	$7,855,526
18	Net Income		$29,410,997
19	Rate Base	$473,468,036	
20	Wtd Cost of Equity (Common + Preferred)	6.21%	
21	Required Return	$29,410,997	$29,410,997
22	Variance		$0

WKP A.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	5,515	0.831%
3	CTX	263,781	39.766%
4	North Texas	16,082	2.425%
5	RGV	65,183	9.827%
6	Gulf Coast	44,622	6.727%
7	WTX	268,147	40.424%
8	Total TGS	663,331	100.000%
9	Service Area Factor for this Filing		46.493%

Based on Test Year Average Total Billed Customers

Source: WKP A.b Customer Allocation Factors.xlsx

SCHEDULE B

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$648,474,688	$9,080,998	$657,555,686
2	Completed Construction Not Classified	C-1	60,337,698	19,967,929	80,305,627
3	Accumulated Reserves for Depreciation and Amortization	D	(187,235,275)	5,052,510	(182,182,765)
4	Net Plant in Service		$521,577,111	$34,101,437	$555,678,548
	OTHER RATE BASE ITEMS				
5	Materials and Supplies Inventory	B-1	$4,472,673	($200,533)	$4,272,141
6	Prepayments	B-2	2,593,146	(11,333)	2,581,813
7	Rule 8.209 Regulatory Asset - DIMP Deferrals	B-3	528,827	0	528,827
8	Pension & OPEB Regulatory Asset	B-4	1,704,879	0	1,704,879
9	Prepaid Pension Asset	B-5	23,340,745	0	23,340,745
10	Cash Working Capital	B-6	0	(4,999,624)	(4,999,624)
	NON-INVESTOR SUPPLIED FUNDS				
11	Customer Deposits	B-7	($7,853,752)	$0	($7,853,752)
12	Customer Advances	B-8	(21,363,984)	0	(21,363,984)
13	Accumulated Deferred Taxes	B-9	(80,421,556)	0	(80,421,556)
14	Total Rate Base		$444,578,089	$28,889,947	$473,468,036

WKP B.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

SUMMARY OF PLANT ADJUSTMENTS

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK	ADJUSTMENTS	ADJUSTED TEST YEAR
			(a)	(b)	(c)
1	PLANT IN SERVICE	Schedule C	$648,474,688		$657,555,686
2	Excludable Meals and Hotel	WKP C.a, C.b and C.c		($17,457)	
3	Plant Miscoded to Service Area	WKP C.a		7,471	
4	TGS Direct Post Test Year Adjustment to include plant at 9/30/2019	WKP C.a		6,749,513	
5	Asset Not Used by TGS Division	WKP C.b		(20,155)	
6	Asset with Insufficient Documentation	WKP C.b		(188,761)	
7	TGS DIV Post Test Year Adjustment to include plant at 9/30/2019	WKP C.b		39,552	
8	Vertex Duplicate Sales Tax	WKP C.c		19	
9	Artwork	WKP C.c		(5,792)	
10	ONE Gas Aviation	WKP C.c		(1,595,084)	
11	ONE Gas Aviation Internet	WKP C.c		(15,338)	
12	ONE Gas Aviation Furniture	WKP C.c		(1,391)	
13	ONE Gas Post Test Year Adjustment to include plant at 9/30/2019	WKP C.c		(693,749)	
14	ONE Gas Foundation Software	WKP C.c		(7,553)	
15	Removal of Retiring Asset	WKP C.a		(3,194,402)	
16	OPC	WKP C.a		8,024,125	
17	Total		$648,474,688	$9,080,998	$657,555,686
18	COMPLETED CONSTRUCTION NOT CLASSIFIED	Schedule C-1	$60,337,698		$80,305,627
19	Excludable Meals and Hotel	WKP C-1.a and C-1.c		($2,432)	
20	TGS Direct Post Test Year Adjustment to include plant at 9/30/2019	WKP C-1.a and C-1.c		14,845,010	
21	Plant Miscoded to Service Area	WKP C-1.a		0	
22	Customer Information Center Building	WKP C-1.b		1,597,573	
23	TGS DIV Post Test Year Adjustment to include plant at 9/30/2019	WKP C-1.b		(13,102)	
24	ONE Gas Post Test Year Adjustment to include plant at 9/30/2019	WKP C-1.c		3,540,879	
25	Total		$60,337,698	$19,967,929	$80,305,627
26	ACCUMULATED RESERVES FOR DEPRECIATION AND AMORTIZATION	Schedule D	($187,235,275)		($182,182,765)
27	Plant Miscoded to Service Area	WKP D.a		($24,780)	
28	Removal of Retiring Asset	WKP D.a		3,194,402	
29	OPC	WKP C.a		(2,973,659)	
30	TGS Direct Proforma Adjusment Reserve Balancing 2015	WKP D.a		992,539	
31	TGS Direct Proforma Adjusment Reserve Balancing 2019	WKP D.a		422,703	
32	TGS Direct Post Test Year Adjustment to include reserve at 9/30/2019	WKP D.a		3,167,116	
33	Asset Not Used by TGS Division	WKP D.b		16,648	
34	Asset with Insufficient Documentation	WKP D.b		188,761	
35	TGS DIV Proforma Adjusment Reserve Balancing 2015	WKP D.b		(1,005,098)	
36	TGS DIV Proforma Adjusment Reserve Balancing 2019	WKP D.b		(423,114)	
37	TGS DIV Post Test Year Adjustment to include reserve at 9/30/2019	WKP D.b		(30,401)	
38	Artwork	WKP D.c		1,171	
39	ONE Gas Aviation	WKP D.c		901,529	
40	ONE Gas Foundation Software	WKP D.c		6,559	
41	ONE Gas Post Test Year Adjustment to include reserve at 9/30/2019	WKP D.c		618,132	
42	Total		($187,235,275)	$5,052,510	($182,182,765)

SCHEDULE B-1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

MATERIALS AND SUPPLIES

LINE NO.	DESCRIPTION	DIRECT INVENTORY	DIRECT STORES LOAD	TOTAL
		(a)	(b)	(c)
1	June 30, 2018	$3,832,190	$12,739	$3,844,929
2	July 31, 2018	3,836,384	40,369	3,876,753
3	August 31, 2018	3,983,118	50,617	4,033,736
4	September 30, 2018	3,924,661	48,679	3,973,340
5	October 31, 2018	4,095,598	124,717	4,220,315
6	November 30, 2018	4,219,174	118,478	4,337,652
7	December 31, 2018	4,419,654	49,199	4,468,853
8	January 31,2019	4,422,664	30,856	4,453,520
9	February 28, 2019	4,281,740	(1,151)	4,280,589
10	March 31, 2019	4,375,959	47,617	4,423,575
11	April 30, 2019	4,589,290	28,442	4,617,732
12	May 31, 2019	4,461,243	72,920	4,534,163
13	June 30, 2019	4,428,210	44,463	4,472,673
14	Total Balances at Month-End	$54,869,884	$667,945	$55,537,830
15	13 Month Average	$4,220,760	$51,380	$4,272,141

Source: SCH B-1 TGS Materials and Supplies _CGSA.xlsx
Source: SCH B-1 Stores Balances_CGSA.xlsx

SCHEDULE B-2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PREPAYMENTS

LINE NO.	DESCRIPTION	CENTRAL-GULF DIRECT	TGS DIVISION	CORPORATE	TOTAL
		(a)	(b)	(c)	(d)
1	June 30, 2018	$0	$1,082,719	$15,860,050	
2	July 31, 2018	0	938,196	15,886,317	
3	August 31, 2018	0	780,549	14,587,324	
4	September 30, 2018	0	676,827	13,020,886	
5	October 31, 2018	0	517,996	13,272,088	
6	November 30, 2018	0	2,999,157	13,126,879	
7	December 31, 2018	0	2,813,590	13,384,199	
8	January 31, 2019	0	2,529,639	15,307,579	
9	February 28, 2019	0	2,270,800	16,844,555	
10	March 31, 2019	0	2,222,392	16,281,869	
11	April 30, 2019	0	1,695,275	17,003,807	
12	May 31, 2019	0	2,076,723	18,066,351	
13	June 30, 2019	0	1,630,329	17,103,161	
14	13 Month Average	$0	$1,710,322	$15,365,005	
15	Allocation Factor to TGS	100.0000%	100.0000%	25.0100%	
16	Allocation Factor to Service Area	100.0000%	46.4931%	46.4931%	
17	Total Allocated Prepayments	$0	$795,182	$1,786,631	$2,581,813

WKP B-2.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PREPAYMENTS - TGS DIVISION

LINE NO.	MONTH/YEAR ENDING	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
	(a)	(b)	(c)	(d) = (b)+(c)
1	June 30, 2018	$1,082,719	$0	$1,082,719
2	July 31, 2018	938,196	0	938,196
3	August 31, 2018	780,549	0	780,549
4	September 30, 2018	676,827	0	676,827
5	October 31, 2018	517,996	0	517,996
6	November 30, 2018	3,006,564	(7,407)	2,999,157
7	December 31, 2018	2,820,997	(7,407)	2,813,590
8	January 31, 2019	2,548,157	(18,518)	2,529,639
9	February 28, 2019	2,270,800	0	2,270,800
10	March 31, 2019	2,189,059	33,333	2,222,392
11	April 30, 2019	1,695,275	0	1,695,275
12	May 31, 2019	2,076,723	0	2,076,723
13	June 30, 2019	1,630,329	0	1,630,329
14	13-Month Average	$1,710,322	$0	$1,710,322
15	Allocation Factor to TGS	100%	100%	100%
16	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%
17	Total Allocated Prepayments	$795,182	$0	$795,182
18	Grand Total Allocated Prepayments			

Source: WKP B-2.a.1 Prepayments - TGS Division Detail (CONFIDENTIAL).xlsx

WKP B-2.b.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PREPAYMENTS - CORPORATE ALLOCATED THROUGH DISTRIGAS

LINE NO.	MONTH/YEAR ENDING	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
	(a)	(b)	(c)	(d) = (b)+(c)
1	June 30, 2018	$15,877,905	($17,855)	$15,860,050
2	July 31, 2018	15,896,364	(10,047)	15,886,317
3	August 31, 2018	14,594,998	(7,674)	14,587,324
4	September 30, 2018	13,082,977	(62,091)	13,020,886
5	October 31, 2018	13,326,127	(54,039)	13,272,088
6	November 30, 2018	13,173,775	(46,896)	13,126,879
7	December 31, 2018	13,454,660	(70,461)	13,384,199
8	January 31, 2019	15,369,635	(62,056)	15,307,579
9	February 28, 2019	16,898,207	(53,652)	16,844,555
10	March 31, 2019	16,528,842	(246,972)	16,281,869
11	April 30, 2019	17,240,649	(236,842)	17,003,807
12	May 31, 2019	18,278,126	(211,774)	18,066,351
13	June 30, 2019	17,289,864	(186,703)	17,103,161
14	13-Month Average	$15,462,471	($97,466)	$15,365,005
15	Pro Forma, Q3 2019, Allocation Factor to TGS	25.0100%	25.0100%	25.0100%
16	13-Month Average Allocated to TGS	$3,867,164	($24,376)	$3,842,788
17	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%
18	Total Allocated Prepayments	$1,797,964	($11,333)	$1,786,631

Source: WKP B-2.b.1 Prepayments - ONE Gas Corp Prepayments Detail (CONFIDENTIAL).xlsx

SCHEDULE B-3

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

RULE 8.209 REGULATORY ASSET

LINE NO.	FERC ACCOUNT	TEST YEAR ACCRUAL	ADJUSTMENT TO ACCRUAL	TOTAL ACCRUAL
		(a)	(b)	(c)
1	(374.2) Land Rignts	$15	$0	$15
2	(376) Mains	167,383	0	167,383
3	(376.9) Cathodic Protection Anodes	9,878	0	9,878
4	(378) Meas & Reg Stat Eq-General	28,784	0	28,784
5	(380) Services	311,143	0	311,143
6	(380.1) Ind Service Line Equip	15	0	15
7	(380.2) Comm Service Line Equip	1,005	0	1,005
8	(380.4) Yard Lines-Customer Svc	1,317	0	1,317
9	(381) Meters	607	0	607
10	(382) Meter Installations	(143)	0	(143)
11	(383) House Regulators	2,280	0	2,280
12	(385) Ind Meas & Reg Sta Equip	6,168	0	6,168
13	(397) Communication Equipment	375	0	375
14	Total	$528,827	$0	$528,827

Source: SCH B-3 CGSA Rule 8.209 Accrual.xlsx

WKP B-3.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

RULE 8.209 REGULATORY ASSET

LINE NO.	PROJECT NO.	SERVICE AREA	DEPRECIATION	PROPERTY TAX	ROE	ROI	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	091.053.7202.005100	Central Texas	$10,268	$5,471	$43,303	$26,512	$85,554
2	091.053.7202.010270	Central Texas	(0)	10	83	51	144
3	091.053.7202.010398	Central Texas	378	157	1,244	761	2,541
4	091.053.7202.010402	Central Texas	(363)	1,587	12,606	7,718	21,548
5	091.053.7202.010413	Central Texas	49	23	179	110	361
6	091.053.7202.010480	Central Texas	734	329	2,599	1,591	5,252
7	091.053.7202.010515	Central Texas	1,521	705	5,575	3,413	11,213
8	091.053.7202.010523	Central Texas	2,592	1,019	8,060	4,934	16,605
9	091.053.7202.010537	Central Texas	191	77	608	372	1,248
10	091.053.7202.010552	Central Texas	216	97	765	468	1,546
11	091.053.7202.010585	Central Texas	1,126	504	3,983	2,438	8,051
12	091.053.7202.010589	Central Texas	248	114	899	550	1,810
13	091.053.7202.010591	Central Texas	39	17	137	84	277
14	091.053.7202.010596	Central Texas	80	45	358	219	702
15	091.053.7202.010597	Central Texas	279	127	1,006	616	2,028
16	091.053.7202.010599	Central Texas	680	357	2,838	1,738	5,613
17	091.053.7202.010601	Central Texas	69	28	218	133	447
18	091.053.7202.010604	Central Texas	453	255	2,024	1,239	3,971
19	091.053.7202.010605	Central Texas	170	68	538	330	1,106
20	091.053.7202.010615	Central Texas	176	78	619	379	1,251
21	091.053.7202.010619	Central Texas	28	10	78	48	163
22	091.053.7202.010622	Central Texas	161	65	516	316	1,058
23	091.053.7202.010624	Central Texas	52	27	214	131	424
24	091.053.7202.010626	Central Texas	153	71	564	345	1,133
25	091.053.7202.010627	Central Texas	160	70	556	340	1,126
26	091.053.7202.010629	Central Texas	143	66	527	323	1,059
27	091.053.7202.010633	Central Texas	92	35	273	167	566
28	091.053.7202.010642	Central Texas	45	22	172	106	345
29	091.053.7202.010647	Central Texas	128	60	478	293	959
30	091.053.7202.010649	Central Texas	50	26	209	128	413
31	091.053.7202.010662	Central Texas	2	1	12	7	22
32	091.053.7202.010666	Central Texas	83	39	310	189	621
33	091.053.7292.005100	Central Texas	1	2	15	9	27
34	091.053.7301.005100	South Texas	13	30	230	141	414
35	091.053.7302.005100	South Texas	(0)	0	0	0	(0)
36	091.053.7303.005100	South Texas	17	42	329	202	590
37	091.053.7304.005100	South Texas	3	13	103	63	182
38	091.053.7306.005100	South Texas	0	10	75	46	131
39	091.053.7307.005100	South Texas	(1)	2	15	9	25
40	091.053.7308.005100	South Texas	0	25	197	121	344
41	091.053.7450.005100	Galveston	158	76	601	369	1,204
42	091.053.7550.005100	South Jefferson	473	222	1,723	1,060	3,478
43	091.053.7550.010046	South Jefferson	62	24	190	117	393
44	091.054.7202.005100	Central Texas	23,769	11,928	94,439	57,819	187,955
45	091.054.7202.010992	Central Texas	(2)	72	569	348	987
46	091.054.7202.011005	Central Texas	(0)	7	56	34	97
47	091.054.7202.011006	Central Texas	122	57	449	275	902

WKP B-3.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
48	091.054.7202.011041	Central Texas	(1)	135	1,072	656	1,862
49	091.054.7202.011059	Central Texas	133	61	484	296	974
50	091.054.7202.011060	Central Texas	(11)	67	532	326	914
51	091.054.7202.011062	Central Texas	(0)	32	255	156	444
52	091.054.7202.011123	Central Texas	452	209	1,650	1,010	3,321
53	091.054.7202.011125	Central Texas	660	307	2,428	1,487	4,882
54	091.054.7202.011129	Central Texas	75	31	241	147	494
55	091.054.7202.011131	Central Texas	339	156	1,238	758	2,491
56	091.054.7202.011132	Central Texas	367	161	1,275	781	2,583
57	091.054.7202.011134	Central Texas	617	280	2,217	1,358	4,472
58	091.054.7202.011139	Central Texas	187	87	688	421	1,383
59	091.054.7202.011140	Central Texas	207	92	730	447	1,477
60	091.054.7202.011141	Central Texas	981	492	3,898	2,387	7,758
61	091.054.7202.011142	Central Texas	823	371	2,934	1,796	5,924
62	091.054.7202.011143	Central Texas	37	18	146	89	290
63	091.054.7202.011146	Central Texas	263	110	872	534	1,779
64	091.054.7202.011147	Central Texas	210	93	738	452	1,493
65	091.054.7202.011149	Central Texas	669	322	2,551	1,562	5,104
66	091.054.7202.011150	Central Texas	60	32	252	154	499
67	091.054.7202.011152	Central Texas	619	300	2,376	1,455	4,751
68	091.054.7202.011154	Central Texas	99	44	350	214	708
69	091.054.7202.011155	Central Texas	480	261	2,074	1,270	4,085
70	091.054.7202.011156	Central Texas	472	219	1,737	1,063	3,491
71	091.054.7202.011157	Central Texas	195	87	685	419	1,385
72	091.054.7202.011160	Central Texas	140	62	493	302	997
73	091.054.7202.011172	Central Texas	153	65	513	314	1,045
74	091.054.7202.011173	Central Texas	26	13	104	64	207
75	091.054.7202.011179	Central Texas	11	5	40	25	80
76	091.054.7292.005100	Central Texas	(0)	(0)	(0)	(0)	(0)
77	091.054.7300.010003	South Texas	17	7	59	36	119
78	091.054.7300.010013	South Texas	5	2	15	9	31
79	091.054.7300.010018	South Texas	44	20	157	96	317
80	091.054.7300.010020	South Texas	32	11	87	53	182
81	091.054.7300.010021	South Texas	123	35	276	169	602
82	091.054.7300.010022	South Texas	62	26	206	126	420
83	091.054.7300.010023	South Texas	76	34	269	164	543
84	091.054.7300.010025	South Texas	66	28	218	134	445
85	091.054.7300.010026	South Texas	11	5	37	23	76
86	091.054.7300.010028	South Texas	105	43	343	210	701
87	091.054.7300.010029	South Texas	355	135	1,071	656	2,217
88	091.054.7300.010030	South Texas	139	64	504	309	1,015
89	091.054.7300.010034	South Texas	61	28	218	133	440
90	091.054.7300.010040	South Texas	74	36	289	177	577
91	091.054.7301.005100	South Texas	62	668	5,197	3,182	9,109
92	091.054.7302.005100	South Texas	28	130	1,016	622	1,796
93	091.054.7303.005100	South Texas	85	372	2,897	1,774	5,128
94	091.054.7304.005100	South Texas	75	292	2,273	1,391	4,031

WKP B-3.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
95	091.054.7306.005100	South Texas	35	108	845	517	1,506
96	091.054.7307.005100	South Texas	30	159	1,265	775	2,229
97	091.054.7308.005100	South Texas	8	76	595	364	1,044
98	091.054.7450.005100	Galveston	1,132	492	3,812	2,345	7,781
99	091.054.7450.010089	Galveston	20	6	45	28	99
100	091.054.7501.005100	South Jefferson	133	60	475	292	960
101	091.054.7502.005100	South Jefferson	291	124	978	601	1,994
102	091.054.7503.005100	South Jefferson	83	53	426	262	825
103	091.054.7550.005100	South Jefferson	1,164	505	3,917	2,410	7,996
104	091.054.7550.010332	South Jefferson	663	234	1,821	1,120	3,838
105	091.054.7550.010333	South Jefferson	171	69	536	329	1,105
106	091.054.7550.010334	South Jefferson	48	19	145	89	302
107	091.054.7550.010335	South Jefferson	69	28	215	132	444
108	091.054.7550.010336	South Jefferson	164	58	449	276	947
109	091.054.7550.010337	South Jefferson	69	27	209	128	432
110	091.054.7550.010338	South Jefferson	2,096	817	6,351	3,907	13,171
111	091.054.7550.010339	South Jefferson	1,760	698	5,424	3,337	11,219
112	091.054.7550.010340	South Jefferson	113	44	338	208	704
113	091.054.7550.010341	South Jefferson	46	19	145	89	298
114	091.054.7550.010344	South Jefferson	28	13	96	59	196
115	091.054.7550.010345	South Jefferson	153	62	485	299	999
116	091.054.7550.010347	South Jefferson	126	48	373	229	776
117	091.054.7550.010349	South Jefferson	28	13	96	59	196
118	091.054.7550.010352	South Jefferson	20	9	69	42	141
119	091.054.7550.010356	South Jefferson	35	19	143	88	284
120	091.054.7550.010358	South Jefferson	28	12	93	57	190
121	091.054.7550.010360	South Jefferson	32	27	206	127	392
122	091.054.7550.010362	South Jefferson	36	14	110	68	228
			$62,882	$33,932	$267,904	$164,109	$528,827

Source: SCH B-3 CGSA Rule 8.209 Accrual.xlsx

SCHEDULE B-4

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$967,260
2	Reg Assets Def OPEB Recovery	1823	WKP B-4.a	(18,666)
3	Regulatory Assets Proforma Amortization July 2019 Through April 2020	4073		($241,210)
4	Deferred Pension and OPEB since last rate cases	1860		997,496
5	Total			$1,704,879

Source: SCH B-4 Trial Balance Pension OPEB Deferral Jun 30 2019_CGSA.xlsx

WKP B-4.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PENSION AND OTHER POST EMPLOYMENT BENEFITS REGULATORY ASSET

PENSION

LINE NO.	FERC ACCOUNT	MONTH	DESCRIPTION	2016	2017	2018	2019	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	1823	January	Reg Assets Def Pension Recovery	$0	($24,567)	($24,567)	($24,567)	($73,701)
2	1823	February	Reg Assets Def Pension Recovery	0	(24,567)	(24,567)	(24,567)	(73,701)
3	1823	March	Reg Assets Def Pension Recovery	0	(24,567)	(24,567)	(24,567)	(73,701)
4	1823	April	Reg Assets Def Pension Recovery	0	(24,567)	(24,567)	(24,567)	(73,701)
5	1823	May	Reg Assets Def Pension Recovery	182,458	(24,567)	(24,567)	(24,567)	108,757
6	1823	June	Reg Assets Def Pension Recovery	(2,570)	(24,567)	(24,567)	(24,567)	(76,271)
7	1823	July	Reg Assets Def Pension Recovery	(2,570)	(24,567)	(24,567)	0	(51,704)
8	1823	August	Reg Assets Def Pension Recovery	(2,570)	(24,567)	(24,567)	0	(51,704)
9	1823	September	Reg Assets Def Pension Recovery	(2,570)	(24,567)	(24,567)	0	(51,704)
10	1823	October	Reg Assets Def Pension Recovery	(2,570)	(24,567)	(24,567)	0	(51,704)
11	1823	November	Reg Assets Def Pension Recovery	1,559,226	(24,567)	(24,567)	0	1,510,092
12	1823	December	Reg Assets Def Pension Recovery	(24,567)	(24,567)	(24,567)	0	(73,701)
13			Grand Total	$1,704,269	($294,804)	($294,804)	($147,402)	$967,260

OPEB

LINE NO.	FERC ACCOUNT	MONTH	DESCRIPTION	2016	2017	2018	2019	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
14	1823	January	Reg Assets Def OPEB Recovery	$0	$446	$446	$446	$1,338
15	1823	February	Reg Assets Def OPEB Recovery	0	446	446	446	1,338
16	1823	March	Reg Assets Def OPEB Recovery	0	446	446	446	1,338
17	1823	April	Reg Assets Def OPEB Recovery	0	446	446	446	1,338
18	1823	May	Reg Assets Def OPEB Recovery	9,801	446	446	446	11,139
19	1823	June	Reg Assets Def OPEB Recovery	(138)	446	446	446	1,200
20	1823	July	Reg Assets Def OPEB Recovery	(138)	446	446	0	754
21	1823	August	Reg Assets Def OPEB Recovery	(138)	446	446	0	754
22	1823	September	Reg Assets Def OPEB Recovery	(138)	446	446	0	754
23	1823	October	Reg Assets Def OPEB Recovery	(138)	446	446	0	754
24	1823	November	Reg Assets Def OPEB Recovery	(41,600)	446	446	0	(40,708)
25	1823	December	Reg Assets Def OPEB Recovery	446	446	446	0	1,338
26			Grand Total	($32,044)	$5,351	$5,351	$2,676	($18,666)
27			Total Pension and OPEB	$1,672,225	($289,452)	($289,452)	($144,726)	$948,594

Source: WKP B-4.a_CGSA (CONFIDENTIAL).xlsx

SCHEDULE B-5

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PREPAID PENSION ASSET

LINE NO.	YEAR	PREPAID PENSION BALANCE
	(a)	(b)
1	Perpaid Pension Asset - TGS	$50,202,599
2	Allocation to Service Area	46.49%
3	Prepaid Pension Asset - CGSA	$23,340,745

Source: SCH B-5 Prepaid Pension Asset Jun 2019_CGSA.xlsx

SCHEDULE B-6

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$75,042,680	$205,596	39.30	A	(40.82)	B	(1.52)	($312,837)
3	Labor - Regular Payroll Expense	21,411,135	58,661	39.30	A	(22.75)	C	16.55	970,985
4	Labor - Annual Performance Bonus Expense	4,511,994	12,362	39.30	A	(243.29)	C	(203.99)	(2,521,661)
5	Non-Labor - Other O&M Expense	25,396,115	69,578	39.30	A	(39.85)	C	(0.55)	(38,271)
6	Total O&M Expenses	$126,361,925	$346,197						($1,901,784)
7	Federal Income Taxes								
8	Current Income Taxes	$7,855,526	$21,522	39.30	A	(38.50)	D	0.80	$17,232
9	Deferred Income Taxes	0	0	0.00		0.00		0.00	0
10	Total Federal Income Taxes	$7,855,526	$21,522						$17,232
11	Taxes Other Than Income Taxes								
12	FICA	$1,531,862	$4,197	39.30	A	(12.75)	E	26.55	$111,442
13	Federal Unemployment	14,132	39	39.30	A	(30.08)	E	9.22	357
14	State Unemployment	38,180	105	39.30	A	(30.09)	E	9.21	964
15	State Gross Receipts	3,236,984	8,868	39.30	A	(76.14)	E	(36.84)	(326,719)
16	Local Franchise Tax	8,845,495	24,234	39.30	A	(94.26)	E	(54.96)	(1,331,904)
17	State Franchise Tax	1,544,261	4,231	39.30	A	47.71	E	87.01	368,122
18	Ad Valorem	4,385,203	12,014	39.30	A	(199.16)	E	(159.86)	(1,920,553)
19	Sales Tax	4,044,485	11,081	39.30	A	(35.42)	E	3.88	42,950
20	RRC Gas Utility Tax	46,734	128	39.30	A	(89.80)	E	(50.50)	(6,466)
21	Taxes Other Than Income Taxes	$23,687,337	$64,897		A				($3,061,807)
22	Interest on Customer Deposits	$150,792	$413	39.30	A	(168.23)	F	(128.93)	($53,265)
23	Depreciation Expense	$21,681,983	$59,403	0.00		0.00		0.00	$0
24	Return	$37,529,690	$102,821	0.00		0.00		0.00	$0
25	Total	$217,267,252	$595,253						($4,999,624)

less purchased gas	(75,042,680)
less gross receipts	(3,236,984)
less local franchise	(8,845,495)
less sales tax	(4,044,485)
less RRC Gas Utility tax	(46,734)
Adjusted total	$ 126,050,873
Rev Rqmt from Sch A	126,050,873
Difference	$ -

Source: SCH B-6 CWC_Lead-Lag Study_CGSA.xlsx
Source: SCH B-6 CWC_CGSA Tax.xlsx

SCHEDULE B-7

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE AT SEPTEMBER 30, 2019
		(a)
1	7202 Austin - Incorporated	$5,839,790
2	7203 Sunset Valley - Incorporated	17,840
3	7204 Rollingwood - Incorporated	6,739
4	7205 West Lake Hills - Incorporated	22,075
5	7206 Cedar Park - Incorporated	36,445
6	7207 Aus Berg Intl Airport - Incorporated	8,250
7	7208 Austin - Environs	264,078
8	7209 West Lake Hills - Environs	4,245
9	7216 Cedar Park - Environs	17,230
10	7260 Lakeway - Incorporated	2,005
11	7262 Bee Cave - Incorporated	25,325
12	7263 Bee Cave - Environs	3,752
13	7292 Kyle - Incorporated	18,737
14	7293 Kyle - Environs	300
15	7294 Dripping Springs - Incorporated	11,925
16	7295 Dripping Springs - Environs	31,625
17	7297 Buda - Environs	21,973
18	7301 Yoakum - Incorporated	42,930
19	7302 Shiner - Incorporated	16,708
20	7303 Cuero - Incorporated	50,240
21	7304 Gonzales - Incorporated	49,870
22	7306 Luling - Incorporated	31,489
23	7307 Lockhart - Incorporated	74,607
24	7308 Nixon - Incorporated	8,759
25	7309 Nixon - Environs	500
26	7310 Yaokum - Environs	1,205
27	7312 Shiner - Environs	400
28	7313 Cuero - Environs	8,774
29	7314 Gonzales - Environs	1,508
30	7316 Luling - Environs	75
31	7317 Lockhart - Environs	175
32	7401 Jamaica Beach - Incorporated	3,635
33	7402 Bayou Vista - Incorporated	8,621
34	7412 Bayou Vista - Environs	1,055
35	7450 Galveston - Incorporated	377,824
36	7501 Groves - Incorporated	129,389
37	7502 Nederland - Incorporated	123,544
38	7503 Port Neches - Incorporated	78,022
39	7509 Beaumont - Incorporated	250
40	7512 Nederland - Environs	14,475
41	7550 Port Arthur - Incorporated	497,365
42	Total Test Year Customer Deposits	$7,853,752

Source: SCH B-7 CGSA Customer Deposit Balances.xlsx

SCHEDULE B-8

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CUSTOMER ADVANCES

LINE NO.	FERC ACCOUNT	DESCRIPTION	ENDING BALANCE AT SEPTEMBER 30, 2019
			(a)
1	2520	LINE EXT DEPOSITS RECEIVED	($2,397)
2	2520	LINE EXT DEPOSITS RECEIVED	(1,072)
3	2520	LINE EXT DEPOSITS FORFEITED	12,249,177
4	2520	LINE EXT DEPOSITS RECEIVED	(47,338,190)
5	2520	LINE EXT DEPOSITS REIMBURSED	14,510,729
6	2520	LINE EXT DEPOSITS RECEIVED	(23,050)
7	2520	LINE EXT DEPOSITS RECEIVED	(4,060)
8	2520	LINE EXT DEPOSITS RECEIVED	(10,049)
9	2520	LINE EXT DEPOSITS RECEIVED	(33,279)
10	2520	LINE EXT DEPOSITS FORFEITED	461,604
11	2520	LINE EXT DEPOSITS RECEIVED	(294,575)
12	2520	LINE EXT DEPOSITS REIMBURSED	16,102
13	2520	LINE EXT DEPOSITS FORFEITED	1,496
14	2520	LINE EXT DEPOSITS RECEIVED	(21,051)
15	2520	LINE EXT DEPOSITS RECEIVED	(2,787)
16	2520	LINE EXT DEPOSITS RECEIVED	(324,502)
17	2520	LINE EXT DEPOSITS REIMBURSED	64,003
18	2520	LINE EXT DEPOSITS FORFEITED	23,550
19	2520	LINE EXT DEPOSITS RECEIVED	(98,950)
20	2520	LINE EXT DEPOSITS RECEIVED	(1,931)
21	2520	LINE EXT DEPOSITS FORFEITED	3,994
22	2520	LINE EXT DEPOSITS RECEIVED	(19,059)
23	2520	LINE EXT DEPOSITS RECEIVED	(2,148)
24	2520	LINE EXT DEPOSITS FORFEITED	12,228
25	2520	LINE EXT DEPOSITS RECEIVED	(299,318)
26	2520	LINE EXT DEPOSITS REIMBURSED	1,615
27	2520	LINE EXT DEPOSITS FORFEITED	69,154
28	2520	LINE EXT DEPOSITS RECEIVED	(359,762)
29	2520	LINE EXT DEPOSITS REIMBURSED	55,213
30	2520	LINE EXT DEPOSITS REIMBURSED	3,333
31		Total	($21,363,984)

Source: SCH B-8 CGSA Customer Advances Balances.xlsx

SCHEDULE B-9

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DECSCRIPTION	ADIT AT 21% AT 9/30/2019	UNAMORTIZED EXCESS ADIT AT 9/30/2019	TOTAL ALLOCATED ADIT TO SERVICE AREA AT 9/30/2019
		(a)	(b)	(c)
1	Central Gulf Service Area Plant Assets Depreciation	($61,333,789)	($33,964,349)	($95,298,138)
2	Central Gulf Service Area Direct Plant Repairs	(18,562,936)	(10,622,000)	(29,184,936)
3	Subtotal CGSA Direct Plant Assets Depreciation	($79,896,725)	($44,586,349)	($124,483,074)
4	Central Gulf Service Area Other Rate Base Items	(5,420,956)	(3,136,047)	(8,557,003)
5	TGS Division Plant Assets Depreciation	(58,273)	(264,573)	(322,846)
6	ONEGAS Plant Assets Depreciation	(2,766,140)	(1,542,000)	(4,308,140)
7	Central Gulf Service Area NOL	36,180,705	21,068,803	57,249,507
8	ADFIT - Accumulated Deferred Federal Income Taxes	($51,961,390)	($28,460,166)	($80,421,556)

Source: SCH B-9 CGSA ADIT WPs 6.30.2019 updt to 9.30.xlsx
SCH B-9 CTGCSA TYE 06.30.19 updt to 9.30 Reg NOL Master.xlsx

SCHEDULE C

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$621,269,889	$11,586,707	$632,856,596
2	Allocated TGS Division Plant In Service	WKP C.b	2,231,250	(174,543)	2,056,706
3	Allocated Corporate Plant In Service	WKP C.c	24,973,550	(2,331,166)	22,642,384
4	Total Plant In Service		$648,474,688	$9,080,998	$657,555,686

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1010 6/30/2019	FERC RECLASS 06/30/2019	MEALS & HOTEL ADJUSTMENTS ACCT 1010 6/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010 6/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010 6/30/2019	REMOVAL OF RETIRING ASSETS 6/30/2019	Addition of OPC High Pressure Distribution Line 6/30/2019	Total Adjusments for TYE 6/30/2019	DIRECT TEST YEAR ADJUSTED ACCT 1010 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	DIRECT ADJUSTED AT ACCT 1010
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	INTANGIBLE PLANT											
1	(301) Organization	$56,257	$0	$0	$0	$0	$0	$0	$0	$56,257	$0	$56,257
2	(301) Organization- OPC	0	0	0	0	0	0	1,307	1,307	1,307	0	1,307
3	(302) Franchises & Consents	393,474	0	0	0	0	0	0	0	393,474	0	393,474
4	(303) Misc. Intangible	739,593	0	0	0	0	0	0	0	739,593	0	739,593
5	(303) Misc. Intangible- OPC	0	0	0	0	0	0	14,336	14,336	14,336	0	14,336
6	Total Intangible Plant	$1,189,323	$0	$0	$0	$0	$0	$15,643	$15,643	$1,204,966	$0	$1,204,966
	GATHERING AND TRANSMISSION PLANT											
7	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0
9	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
10	(329) Other Structures	0	0	0	0	0	0	0	0	0	0	0
11	(332) Field Lines	0	0	0	0	0	0	0	0	0	0	0
12	(333) Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
13	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0
14	(336) Purification Equipment	0	0	0	0	0	0	0	0	0	0	0
15	(337) Other Equip	0	0	0	0	0	0	0	0	0	0	0
16	(365) Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0
17	(365.1) Land - OPC	0	0	0	0	0	0	89,637	89,637	89,637	0	89,637
18	(365.2) Rights of Way - OPC	0	0	0	0	0	0	2,446	2,446	2,446	0	2,446
19	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
20	(366.1) Compressor Station Structure - OPC	0	0	0	0	0	0	2,346	2,346	2,346	0	2,346
21	(367) Mains	4,142,642	0	0	0	0	0	0	0	4,142,642	(156,447)	3,986,195
22	(367) Mains -OPC	0	0	0	0	0	0	6,909,861	6,909,861	6,909,861	0	6,909,861
23	(368) Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
24	(369) Measure/Reg. Station Equipment	211,577	0	0	0	0	0	0	0	211,577	0	211,577
25	(369) Measure/Reg. Station Equipment - OPC	0	0	0	0	0	0	132,499	132,499	132,499	0	132,499
26	(369.1) Measuring Station Equipment - OPC	0	0	0	0	0	0	810,700	810,700	810,700	0	810,700
27	(371) Other Equipment	0	0	0	0	0	0	0	0	0	0	0
28	(371) Other Equipment - OPC	0	0	0	0	0	0	45,840	45,840	45,840	0	45,840
29	Total Gathering and Transmission Plant	$4,354,219	$0	$0	$0	$0	$0	$7,993,328	$7,993,328	$12,347,546	($156,447)	$12,191,099
	DISTRIBUTION PLANT											
30	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	(374.1) Land & Land Rights	19,503	0	0	0	0	0	0	0	19,503	0	19,503
32	(374.2) Land & Land Rights	95,672	0	0	0	0	0	0	0	95,672	0	95,672
33	(375.1) Structures & Improvements	44,795	0	0	0	0	0	0	0	44,795	0	44,795
34	(375.2) Other Distr Systems Struct	4,141	0	0	0	0	0	0	0	4,141	0	4,141

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1010 6/30/2019	FERC RECLASS 06/30/2019	MEALS & HOTEL ADJUSTMENTS ACCT 1010 6/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010 6/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010 6/30/2019	REMOVAL OF RETIRING ASSETS 6/30/2019	Addition of OPC High Pressure Distribution Line 6/30/2019	Total Adjusments for TYE 6/30/2019	DIRECT TEST YEAR ADJUSTED ACCT 1010 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	DIRECT ADJUSTED AT ACCT 1010
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
35	(376) Mains	263,905,354	(29,948)	0	0	(242)	0	0	(30,190)	263,875,164	735,484	264,610,649
36	(376.9) Mains - Cathodic Protection Anodes	27,336,965	29,948	0	0	0	(1,155,062)	0	(1,125,114)	26,211,852	162,278	26,374,130
37	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0
38	(378) Meas. & Reg. Station - General	10,468,864	0	0	0	0	0	0	0	10,468,864	0	10,468,864
39	(379) Meas. & Reg. Station - C.G.	2,577,593	0	0	0	0	0	0	0	2,577,593	0	2,577,593
40	(380) Services	174,234,339	0	0	(7,808)	30,583	0	0	22,775	174,257,113	5,888,304	180,145,418
41	(380.1) Ind Service Line Equip	816	0	0	0	0	0	0	0	816	0	816
42	(380.2) Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0
43	(381) Meters	64,071,051	0	0	(173)	0	0	0	(173)	64,070,877	0	64,070,877
44	(382) Meter Installations	0	0	0	0	0	0	0	0	0	0	0
45	(383) House Regulators	8,976,854	0	0	(595)	0	0	0	(595)	8,976,259	1,268	8,977,527
46	(385) Indust. Meas. & Reg. Stat. Equipment	12,804,681	0	0	(3,657)	3,279	0	0	(378)	12,804,303	15,448	12,819,751
47	(386) Other Property on Customer Premises	1,063,249	0	0	0	0	0	0	0	1,063,249	0	1,063,249
48	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0
49	Total Distribution Plant	$565,603,877	$0	$0	($12,234)	$33,620	($1,155,062)	$0	($1,133,675)	$564,470,202	$6,802,783	$571,272,984
	GENERAL PLANT											
50	(389) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	(389.1) Land & Land Rights	48,883	0	0	0	0	0	0	0	48,883	0	48,883
52	(390) Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0
53	(390.1) Structures & Improvements	4,355,662	0	0	0	0	0	0	0	4,355,662	47,514	4,403,176
54	(390.2) Leasehold Improvements	1,150,707	0	0	0	0	0	0	0	1,150,707	63,458	1,214,164
55	(391) Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0
56	(391.1) Office Furniture & Equipment	967,544	0	0	0	0	0	0	0	967,544	(5,229)	962,315
57	(391.1) Office Furniture & Equipment - OPC	0	0	0	0	0	0	14,671	14,671	14,671	0	14,671
58	(391.9) Computer & Equipment	3,849,861	0	0	0	0	(2,039,341)	0	(2,039,341)	1,810,520	53,238	1,863,758
59	(392) Transportation Equipment	13,062,025	0	0	0	0	0	0	0	13,062,025	(79,573)	12,982,452
60	(393) Stores Equipment	8,809	0	0	0	0	0	0	0	8,809	0	8,809
61	(394) Tools, Shop & Garage	6,842,725	0	0	0	0	0	0	0	6,842,725	(17,661)	6,825,064
62	(394.1) Tools	59,471	0	0	0	0	0	0	0	59,471	45,757	105,228
63	(394.1) Tools - OPC	0	0	0	0	0	0	483	483	483	0	483
64	(395) CNG Equipment	0	0	0	0	0	0	0	0	0	0	0
65	(396) Major Work Equipment	1,542,948	0	0	(13,915)	0	0	0	(13,915)	1,529,033	0	1,529,033
66	(397) Communication Equipment	18,103,476	0	0	0	0	0	0	0	18,103,476	(4,325)	18,099,151
67	(398) Miscellaneous General Plant	130,360	0	0	0	0	0	0	0	130,360	0	130,360
68	Total General Plant	$50,122,470	$0	$0	($13,915)	$0	($2,039,341)	$15,154	($2,038,101)	$48,084,368	$103,178	$48,187,546
69	Total Orig Cost Plant in Service	$621,269,889	$0	$0	($26,149)	$33,620	($3,194,402)	$8,024,125	$4,837,194	$626,107,082	$6,749,513	$632,856,596

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1010 6/30/2019	FERC RECLASS 06/30/2019	MEALS & HOTEL ADJUSTMENTS ACCT 1010 6/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010 6/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010 6/30/2019	REMOVAL OF RETIRING ASSETS 6/30/2019	Addition of OPC High Pressure Distribution Line 6/30/2019	Total Adjusments for TYE 6/30/2019	DIRECT TEST YEAR ADJUSTED ACCT 1010 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	DIRECT ADJUSTED AT ACCT 1010
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC-CGSA.xlsx
Source: WKP C.a and WKP D.a OPC Assets Detail – CGSA.xlsx

WKP C.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - POST TEST YEAR SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1010 AT 9/30/2019	Total Adjustments for TYE 6/30/2019	MEALS & HOTEL ADJUSTMENTS ACCT 1010 AT 9/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010 AT 9/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010 AT 9/30/2019	RECLASSIFICATION TO CORRECT CGSA LOCATION ADJUSTMENT ACCT 1010 AT 9/30/2019	REMOVAL OF RETIRING ASSETS	DIRECT ADJUSTED ACCT 1010 AT 9/30/2019	TOTAL CHANGE IN ACCT 1010 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(g)	(i)
	INTANGIBLE PLANT									
1	(301) Organization	$56,257	$0	$0	$0	$0	$0	$0	$56,257	$0
2	(301) Organization- OPC	0	1,307	0	0	0	0	0	1,307	0
3	(302) Franchises & Consents	393,474	0	0	0	0	0	0	393,474	0
4	(303) Misc. Intangible	739,593	0	0	0	0	0	0	739,593	0
5	(303) Misc. Intangible- OPC	0	14,336	0	0	0	0	0	14,336	0
6	Total Intangible Plant	$1,189,323	$15,643	$0	$0	$0	$0	$0	$1,204,966	$0
	GATHERING AND TRANSMISSION PLANT									
7	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0
9	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0
10	(329) Other Structures	0	0	0	0	0	0	0	0	0
11	(332) Field Lines	0	0	0	0	0	0	0	0	0
12	(333) Field Compressor Station Equip	0	0	0	0	0	0	0	0	0
13	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0
14	(336) Purification Equipment	0	0	0	0	0	0	0	0	0
15	(337) Other Equip	0	0	0	0	0	0	0	0	0
16	(365) Land & Land Rights	0	0	0	0	0	0	0	0	0
17	(365.1) Land - OPC	0	89,637	0	0	0	0	0	89,637	0
18	(365.2) Rights of Way - OPC	0	2,446	0	0	0	0	0	2,446	0
19	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0
20	(366.1) Compressor Station Structure - OPC	0	2,346	0	0	0	0	0	2,346	0
21	(367) Mains	3,986,195	0	0	0	0	0	0	3,986,195	(156,447)
22	(367) Mains -OPC	0	6,909,861	0	0	0	0	0	6,909,861	0
23	(368) Compressor Station Equip	0	0	0	0	0	0	0	0	0
24	(369) Measure/Reg. Station Equipment	211,577	0	0	0	0	0	0	211,577	0
25	(369) Measure/Reg. Station Equipment - OPC	0	132,499	0	0	0	0	0	132,499	0
26	(369.1) Measuring Station Equipment - OPC	0	810,700	0	0	0	0	0	810,700	0
27	(371) Other Equipment	0	0	0	0	0	0	0	0	0
28	(371) Other Equipment - OPC	0	45,840	0	0	0	0	0	45,840	0
29	Total Gathering and Transmission Plant	$4,197,772	$7,993,328	$0	$0	$0	$0	$0	$12,191,099	($156,447)
	DISTRIBUTION PLANT									
30	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	(374.1) Land	19,503	0	0	0	0	0	0	19,503	0
32	(374.2) Land Rights	95,672	0	0	0	0	0	0	95,672	0
33	(375.1) Structures & Improvements	44,795	0	0	0	0	0	0	44,795	0
34	(375.2) Other Distr Systems Struct	4,141	0	0	0	0	0	0	4,141	0
35	(376) Mains	264,645,930	(30,190)	0	(5,092)	0	0	0	264,610,649	735,484
36	(376.9) Mains - Cathodic Protection Anodes	27,385,363	(1,125,114)	0	5,092	0	0	108,789	26,374,130	162,278
37	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0	0
38	(378) Meas. & Reg. Station - General	10,468,864	0	0	0	0	0	0	10,468,864	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - POST TEST YEAR SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT BOOK PER ACCT 1010 AT 9/30/2019	Total Adjustments for TYE 6/30/2019	MEALS & HOTEL ADJUSTMENTS ACCT 1010 AT 9/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010 AT 9/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010 AT 9/30/2019	RECLASSIFICATION TO CORRECT CGSA LOCATION ADJUSTMENT ACCT 1010 AT 9/30/2019	REMOVAL OF RETIRING ASSETS	DIRECT ADJUSTED ACCT 1010 AT 9/30/2019	TOTAL CHANGE IN ACCT 1010 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(g)	(i)
39	(379) Meas. & Reg. Station - C.G.	2,577,593	0	0	0	0	0	0	2,577,593	0
40	(380) Services	180,122,606	22,775	0	0	37	0	0	180,145,418	5,888,304
41	(380.1) Services	816	0	0	0	0	0	0	816	0
42	(380.2) Comm Service Line Equip	0	0	0	0	0	0	0	0	0
43	(381) Meters	64,071,051	(173)	0	0	0	0	0	64,070,877	0
44	(382) Meter Installations	0	0	0	0	0	0	0	0	0
45	(383) House Regulators	8,978,122	(595)	0	0	0	0	0	8,977,527	1,268
46	(385) Indust. Meas. & Reg. Stat. Equipment	12,820,128	(378)	0	0	0	0	0	12,819,751	15,448
47	(386) Other Property on Customer Premises	1,063,249	0	0	0	0	0	0	1,063,249	0
48	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0.00
49	Total Distribution Plant	$572,297,833	($1,133,675)	$0	$0	$37	$0	$108,789	$571,272,984	$6,802,783
	GENERAL PLANT									
50	(389) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	(389.1) Land & Land Rights	48,883	0	0	0	0	0	0	48,883	0
52	(390) Structures & Improvements	0	0	0	0	0	0	0	0	0
53	(390.1) Structures & Improvements	4,403,176	0	0	0	0	0	0	4,403,176	47,514
54	(390.2) Leasehold Improvements	1,214,164	0	0	0	0	0	0	1,214,164	63,458
55	(391) Office Furniture & Equipment	0	0	0	0	0	0	0	0	0
56	(391.1) Office Furniture & Equipment	962,315	0	0	0	0	0	0	962,315	(5,229)
57	(391.1) Office Furniture & Equipment - OPC	0	14,671	0	0	0	0	0	14,671	0
57	(391.9) Computer & Equipment	3,903,098	(2,039,341)	0	0	0	0	0	1,863,758	53,238
58	(392) Transportation Equipment	12,982,452	0	0	0	0	0	0	12,982,452	(79,573)
58	(393) Stores Equipment	8,809	0	0	0	0	0	0	8,809	0
59	(394) Tools, Shop & Garage	6,825,064	0	0	0	0	0	0	6,825,064	(17,661)
59	(394.1) Tools	105,228	0	0	0	0	0	0	105,228	45,757
60	(394.1) Tools - OPC	0	483	0	0	0	0	0	483	0
60	(395) CNG Equipment	0	0	0	0	0	0	0	0	0
61	(396) Major Work Equipment	1,542,948	(13,915)	0	0	0	0	0	1,529,033	0
62	(397) Communication Equipment	18,099,151	0	0	0	0	0	0	18,099,151	(4,325)
63	(398) Miscellaneous General Plant	130,360	0	0	0	0	0	0	130,360	0
64	Total General Plant	$50,225,647	($2,038,101)	$0	$0	$0	$0	$0	$48,187,546	$103,178
65	Total Orig Cost Plant in Service	$627,910,576	$4,837,194	$0	$0	$37	$0	$108,789	$632,856,596	$6,749,513

Source: WKP Ca.1 & C-1a CPR 1 101 & 106 Post TY at Sep_2019.xlsx

WKP C.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK Acct 1010 AT 6/30/2019	REMOVE ASSET NOT USED BY DIVISION	ASSET WITH MISSING BACKUP	REMOVE 2010 MEALS & HOTEL	REMOVE 2013 MEALS & HOTEL	REMOVE 2014 MEALS & HOTEL	REMOVE 2015 MEALS & HOTEL	REMOVE 2016 MEALS & HOTEL	REMOVE 2017 MEALS & HOTEL	REMOVE 2018 MEALS & HOTEL	REMOVE 2019 MEALS & HOTEL	TGS DIVISION TEST YEAR ADJUSTED ACCT 1010 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	TGS DIVISION ADJUSTED ACCT 1010 AT 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	INTANGIBLE PLANT														
1	(301) Organization	$127,437	$0	($127,437)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	(302) Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(303) Misc. Intangible	278,560	0	(278,560)	0	0	0	0	0	0	0	0	0	0	0
4	Total Intangible Plant	$405,997	$0	($405,997)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	GATHERING AND TRANSMISSION PLANT														
5	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	(329) Other Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	(332) Field Lines	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	(333) Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	(336) Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	(337) Other Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	(365) Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	(367) Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	(368) Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	(369) Measure/Reg. Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	(371) Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	DISTRIBUTION PLANT														
21	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	(375) Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	(376) Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	(378) Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	(380) Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	(380.2) Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	(381) Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	(382) Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	(383) House Regulators	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	(386) Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Total Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	GENERAL PLANT														
36	(389) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	(390.1) Structures & Improvements	74,162	0	0	0	0	0	(492)	0	0	0	0	73,670	0	73,670
38	(390.2) Leasehold Equipment	149,951	(43,351)	0	0	0	0	0	0	0	0	0	106,600	0	106,600
39	(391.1) Office Furniture & Fixtures	465,812	0	0	0	0	0	0	0	0	0	0	465,812	(27,654)	438,158
40	(391.2) Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41	(391.3) Office Machines	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	(391.4) Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	(391.6) Purchased Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0
44	(391.9) Computer & Equipment	2,601,861	0	0	(97)	(1,053)	(83)	(7,466)	(17)	(482)	(107)	(1,081)	2,591,475	112,724	2,704,198
45	(392.6) Aircraft	0	0	0	0	0	0	0	0	0	0	0	0	0	0
46	(394) Tools	20,328	0	0	0	0	0	(262)	0	0	0	0	20,066	0	20,066

WKP C.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK Acct 1010 AT 6/30/2019	REMOVE ASSET NOT USED BY DIVISION	ASSET WITH MISSING BACKUP	REMOVE 2010 MEALS & HOTEL	REMOVE 2013 MEALS & HOTEL	REMOVE 2014 MEALS & HOTEL	REMOVE 2015 MEALS & HOTEL	REMOVE 2016 MEALS & HOTEL	REMOVE 2017 MEALS & HOTEL	REMOVE 2018 MEALS & HOTEL	REMOVE 2019 MEALS & HOTEL	TGS DIVISION TEST YEAR ADJUSTED ACCT 1010 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	TGS DIVISION ADJUSTED ACCT 1010 AT 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
47	(394.2) Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	(397) Communication Equipment	1,080,989	0	0	0	0	0	0	0	0	0	0	1,080,989	0	1,080,989
49	(398) Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50	Total General Plant	$4,393,102	($43,351)	$0	($97)	($1,053)	($83)	($8,220)	($17)	($482)	($107)	($1,081)	$4,338,611	$85,070	$4,423,681
51	Total Orig Cost Plant in Service	4,799,099	($43,351)	($405,997)	($97)	($1,053)	($83)	($8,220)	($17)	($482)	($107)	($1,081)	$4,338,611	$85,070	$4,423,681
52	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%
53	Total Allocated Plant In Service	$2,231,250	($20,155)	($188,761)	($45)	($490)	($39)	($3,822)	($8)	($224)	($50)	($503)	$2,017,155	$39,552	$2,056,706

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve.xlxs

WKP C.b.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - POST TEST YEAR TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK Acct 1010 AT 9/30/2019	REMOVE ASSET NOT USED BY DIVISION	ASSET WITH MISSING BACKUP	REMOVE 2010 MEALS & HOTEL	REMOVE 2013 MEALS & HOTEL	REMOVE 2014 MEALS & HOTEL	REMOVE 2015 MEALS & HOTEL	REMOVE 2016 MEALS & HOTEL	REMOVE 2017 MEALS & HOTEL	REMOVE 2018 MEALS & HOTEL	REMOVE 2019 MEALS & HOTEL	REMOVE 2019 POST TEST YEAR MEALS & HOTEL	TGS DIVISION ADJUSTED ACCT 1010 AT 9/30/2019	TOTAL CHANGE IN ACCT 1010 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	INTANGIBLE PLANT														
1	(301) Organization	$127,437	$0	($127,437)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	(302) Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(303) Misc. Intangible	278,560	0	(278,560)	0	0	0	0	0	0	0	0	0	0	0
4	Total Intangible Plant	$405,997	$0	($405,997)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	GATHERING AND TRANSMISSION PLANT														
5	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	(329) Other Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	(332) Field Lines	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	(333) Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	(336) Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	(337) Other Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	(365) Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	(367) Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	(368) Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	(369) Measure/Reg. Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	(371) Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	DISTRIBUTION PLANT														
21	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	(375) Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	(376) Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	(378) Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	(380) Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	(380.2) Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	(381) Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	(382) Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	(383) House Regulators	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	(386) Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Total Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	GENERAL PLANT														
36	(389) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	(390.1) Structures & Improvements	74,162	0	0	0	0	0	(492)	0	0	0	0	0	73,670	0
38	(390.2) Leasehold Equipment	149,951	(43,351)	0	0	0	0	0	0	0	0	0	0	106,600	0
39	(391.1) Office Furniture & Fixtures	438,158	0	0	0	0	0	0	0	0	0	0	0	438,158	(27,654)
40	(391.2) Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41	(391.3) Office Machines	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	(391.4) Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	(391.6) Purchased Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0
44	(391.9) Computer & Equipment	2,715,341	0	0	(97)	(1,053)	(83)	(7,466)	(17)	(482)	(107)	(1,081)	(757)	2,704,198	112,724
45	(392.6) Aircraft	0	0	0	0	0	0	0	0	0	0	0	0	0	0
46	(394) Tools	20,328	0	0	0	0	0	(262)	0	0	0	0	0	20,066	0

WKP C.b.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - POST TEST YEAR TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK Acct 1010 AT 9/30/2019	REMOVE ASSET NOT USED BY DIVISION	ASSET WITH MISSING BACKUP	REMOVE 2010 MEALS & HOTEL	REMOVE 2013 MEALS & HOTEL	REMOVE 2014 MEALS & HOTEL	REMOVE 2015 MEALS & HOTEL	REMOVE 2016 MEALS & HOTEL	REMOVE 2017 MEALS & HOTEL	REMOVE 2018 MEALS & HOTEL	REMOVE 2019 MEALS & HOTEL	REMOVE 2019 POST TEST YEAR MEALS & HOTEL	TGS DIVISION ADJUSTED ACCT 1010 AT 9/30/2019	TOTAL CHANGE IN ACCT 1010 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
47	(394.2) Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0
48	(397) Communication Equipment	1,080,989	0	0	0	0	0	0	0	0	0	0	0	1,080,989	0
49	(398) Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50	Total General Plant	$4,478,929	($43,351)	$0	($97)	($1,053)	($83)	($8,220)	($17)	($482)	($107)	($1,081)	($757)	$4,423,681	$85,070
51	Total Orig Cost Plant in Service	4,884,925	($43,351)	($405,997)	($97)	($1,053)	($83)	($8,220)	($17)	($482)	($107)	($1,081)	($757)		
52	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%		
53	Total Allocated Plant In Service	$2,271,153	($20,155)	($188,761)	($45)	($490)	($39)	($3,822)	($8)	($224)	($50)	($503)	($352)		

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve.xlxs

WKP C.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019

PLANT IN SERVICE - CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK Acct 1010 AT 6/30/2019	REMOVE VERTEX DUPLICATE SALES TAX	REMOVE ARTWORK	REMOVE AIRPLANE	REMOVE AIRCRAFT INTERNET	REMOVE AIRPORT FURNITURE	REMOVE ONE GAS FOUNDATION SOFTWARE	REMOVE 2012 MEALS & HOTEL	REMOVE 2013 MEALS & HOTEL	REMOVE 2014 MEALS & HOTEL	REMOVE 2015 MEALS & HOTEL	REMOVE 2016 MEALS & HOTEL	REMOVE 2017 MEALS & HOTEL	REMOVE 2018 MEALS & HOTEL	REMOVE 2019 MEALS & HOTEL	CORPORATE TEST YEAR ADJUSTED ACCT 1010 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	CORPORATE ADJUSTED ACCT 1010 AT 9/30/2019	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	INTANGIBLE PLANT																				
1	(301) Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
2	(302) Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
3	(303) Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
4	Total Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
	GATHERING AND TRANSMISSION PLANT																				
5	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
6	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
8	(329) Other Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
9	(332) Field Lines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
10	(333) Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
12	(336) Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
13	(337) Other Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
14	(365) Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
15	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
16	(367) Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
17	(368) Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
18	(369) Measure/Reg. Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
19	(371) Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
20	Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
	DISTRIBUTION PLANT																				
21	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
22	(375) Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
23	(376) Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
24	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
25	(378) Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
26	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
27	(380) Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
28	(380.2) Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
29	(381) Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
30	(382) Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
31	(383) House Regulators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
32	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
33	(386) Other Property on Customer Premise	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
34	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
35	Total Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		

WKP C.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019

PLANT IN SERVICE - CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK Acct 1010 AT 6/30/2019	REMOVE VERTEX DUPLICATE SALES TAX	REMOVE ARTWORK	REMOVE AIRPLANE	REMOVE AIRCRAFT INTERNET	REMOVE AIRPORT FURNITURE	REMOVE ONE GAS FOUNDATION SOFTWARE	REMOVE 2012 MEALS & HOTEL	REMOVE 2013 MEALS & HOTEL	REMOVE 2014 MEALS & HOTEL	REMOVE 2015 MEALS & HOTEL	REMOVE 2016 MEALS & HOTEL	REMOVE 2017 MEALS & HOTEL	REMOVE 2018 MEALS & HOTEL	REMOVE 2019 MEALS & HOTEL	CORPORATE TEST YEAR ADJUSTED ACCT 1010 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	CORPORATE ADJUSTED ACCT 1010 AT 9/30/2019	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	GENERAL PLANT																				
36	(389) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	25.01%	$0
37	(390.1) Structures & Improvements	41,164	0	0	0	0	0	0	0	0	0	0	0	0	0	0	41,164	167,272	208,436	25.01%	52,130
38	(390.2) Leasehold Improvements	5,080,099	0	0	0	0	0	0	0	0	0	0	0	0	0	(52)	5,080,047	0	5,080,047	25.01%	1,270,520
39	(391.1) Office Furniture & Equipment	3,605,934	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,605,934	0	3,605,934	25.01%	901,844
40	(391.19) Airplane Hanger Furniture	11,870	0	0	0	0	(11,870)	0	0	0	0	0	0	0	0	0	0	0	0	25.01%	0
41	(391.2) Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25.01%	0
42	(391.3) Office Machines	36,237	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36,237	0	36,237	25.01%	9,063
43	(391.4) Audio Visual Equipment	1,402,299	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,402,299	0	1,402,299	25.01%	350,715
44	(391.5) Artwork	49,414	0	(49,414)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25.01%	0
45	(391.6) Purchased Software	81,553,346	192	0	0	0	0	(64,443)	0	(59)	(5,703)	(38,045)	(21,323)	(17,417)	(7,461)	(1,425)	81,397,663	2,741,382	84,139,045	25.01%	21,043,175
46	(391.6) Banner Software	15,274,671	0	0	0	0	0	0	0	0	0	0	0	(355)	0	0	15,274,316	(9,802,713)	5,471,603	30.41%	1,663,919
47	(391.6) PowerPlant System	870,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	870,000	0	870,000	24.02%	208,931
48	(391.6) Riskworks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
49	(391.6) Maximo	3,117,561	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,117,561	0	3,117,561	24.71%	770,306
50	(391.6) Dynamic Risk Assessment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
51	(391.6) Concur Project	47,648	0	0	0	0	0	0	0	0	0	0	0	0	0	0	47,648	0	47,648	27.95%	13,318
52	(391.6) Journey-Employee-ODC Distrigas	69,580,940	0	0	0	0	0	0	(4,632)	(4,830)	0	(3,193)	0	0	0	0	69,568,284	0	69,568,284	25.01%	17,399,028
53	(391.6) Journey-Employee Count	1,848,836	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,848,836	0	1,848,836	27.95%	516,769
54	(391.6) Ariba Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.96%	0
55	(391.6) Accounts Payable Software	903,328	0	0	0	0	0	0	0	0	0	0	0	0	0	0	903,328	0	903,328	30.96%	279,633
56	(391.8) Micro Computer Software	15,800,510	(27)	0	0	0	0	0	0	(51)	(202)	0	0	0	0	0	15,800,230	975,227	16,775,457	25.01%	4,195,542
57	(391.81) Aircraft Computer Equipment	130,857	0	0	0	(130,857)	0	0	0	0	0	0	0	0	0	0	0	0	0	25.01%	0
58	(391.9) Computer & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25.01%	0
59	(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	25.01%	0
60	(394) Tools	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25.01%	0
61	(394.1) Tools	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25.01%	0
62	(394.2) Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25.01%	0
63	(396) Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25.01%	0
64	(397) Communication Equipment	102,489	0	0	0	0	0	0	0	0	0	0	0	0	0	0	102,489	0	102,489	25.01%	25,632
65	(397.2) Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25.01%	0
66	(398) Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25.01%	0
67	Total General Plant	$213,065,925	$164	($49,414)	($13,608,723)	($130,857)	($11,870)	($64,443)	($4,632)	($4,940)	($5,905)	($41,238)	($21,323)	($17,772)	($7,461)	($1,477)	$199,096,035	($5,918,832)	$193,177,204	25.21%	$48,700,525
68	Total Orig Cost Plant in Service	$213,065,925	$164	($49,414)	($13,608,723)	($130,857)	($11,870)	($64,443)	($4,632)	($4,940)	($5,905)	($41,238)	($21,323)	($17,772)	($7,461)	($1,477)	$199,096,035	($5,918,832)	$193,177,204		
69	Allocation Factor to TGS	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%		
70	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%		
71	Total Allocated Plant In Service	$24,973,550	$19	($5,792)	($1,595,084)	($15,338)	($1,391)	($7,553)	($543)	($579)	($692)	($4,834)	($2,499)	($2,083)	($875)	($173)	$23,336,133	($693,749)	$22,642,384		

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve.xlsx

WKP C.c.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK Acct 1010 AT 9/30/2019	REMOVE VERTEX DUPLICATE SALES TAX	REMOVE ARTWORK	REMOVE AIRPLANE	REMOVE AIRCRAFT INTERNET	REMOVE AIRPORT FURNITURE	REMOVE ONE GAS FOUNDATI ON SOFTWARE	REMOVE 2012 MEALS & HOTEL	REMOVE 2013 MEALS & HOTEL	REMOVE 2014 MEALS & HOTEL	REMOVE 2015 MEALS & HOTEL	REMOVE 2016 MEALS & HOTEL	REMOVE 2017 MEALS & HOTEL	REMOVE 2018 MEALS & HOTEL	REMOVE 2019 MEALS & HOTEL	REMOVE 2019 POST TEST YEAR MEALS & HOTEL	CORPORATE ADJUSTED ACCT 1010 AT 9/30/2019	TOTAL CHANGE IN ACCT 1010 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	INTANGIBLE PLANT																		
1	(301) Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	(302) Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	(303) Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Total Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	GATHERING AND TRANSMISSION PLANT																		
5	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	(329) Other Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	(332) Field Lines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	(333) Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	(336) Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	(337) Other Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	(365) Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	(367) Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	(368) Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	(369) Measure/Reg. Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	(371) Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	DISTRIBUTION PLANT																		
21	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	(375) Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	(376) Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	(378) Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	(380) Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	(380.2) Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	(381) Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	(382) Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	(383) House Regulators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	(386) Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Total Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

WKP C.c.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK Acct 1010 AT 9/30/2019	REMOVE VERTEX DUPLICATE SALES TAX	REMOVE ARTWORK	REMOVE AIRPLANE	REMOVE AIRCRAFT INTERNET	REMOVE AIRPORT FURNITURE	REMOVE ONE GAS FOUNDATI ON SOFTWARE	REMOVE 2012 MEALS & HOTEL	REMOVE 2013 MEALS & HOTEL	REMOVE 2014 MEALS & HOTEL	REMOVE 2015 MEALS & HOTEL	REMOVE 2016 MEALS & HOTEL	REMOVE 2017 MEALS & HOTEL	REMOVE 2018 MEALS & HOTEL	REMOVE 2019 MEALS & HOTEL	REMOVE 2019 POST TEST YEAR MEALS & HOTEL	CORPORATE ADJUSTED ACCT 1010 AT 9/30/2019	TOTAL CHANGE IN ACCT 1010 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	GENERAL PLANT																		
36	(389) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
37	(390.1) Structures & Improvements	208,436	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	208,436	167,272
38	(390.2) Leasehold Improvements	5,080,099	0	0	0	0	0	0	0	0	0	0	0	0	0	(52)	0	5,080,047	0
39	(391.1) Office Furniture & Equipment	3,605,934	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,605,934	0
40	(391.19) Airplane Hanger Furniture	11,870	0	0	0	0	(11,870)	0	0	0	0	0	0	0	0	0	0	0	0
41	(391.2) Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	(391.3) Office Machines	36,237	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36,237	0
43	(391.4) Audio Visual Equipment	1,402,299	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,402,299	0
44	(391.5) Artwork	49,414	0	(49,414)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
45	(391.6) Purchased Software	84,296,828	192	0	0	0	0	(64,443)	0	(59)	(5,703)	(38,045)	(21,323)	(17,417)	(7,617)	(1,425)	(1,944)	84,139,045	2,741,382
46	(391.6) Banner Software	5,471,958	0	0	0	0	0	0	0	0	0	0	0	(355)	0	0	0	5,471,603	(9,802,713)
47	(391.6) PowerPlant System	870,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	870,000	0
48	(391.6) Riskworks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
49	(391.6) Maximo	3,117,561	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,117,561	0
50	(391.6) Dynamic Risk Assessment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
51	(391.6) Concur Project	47,648	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	47,648	0
52	(391.6) Journey-Employee-ODC Distrigas	69,580,940	0	0	0	0	0	0	(4,632)	(4,830)	0	(3,193)	0	0	0	0	0	69,568,284	0
53	(391.6) Journey-Employee Count	1,848,836	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,848,836	0
54	(391.6) Ariba Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55	(391.6) Accounts Payable Software	903,328	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	903,328	0
56	(391.8) Micro Computer Software	16,775,737	(27)	0	0	0	0	0	0	(51)	(202)	0	0	0	0	0	0	16,775,457	975,227
57	(391.81) Aircraft Computer Equipment	130,857	0	0	0	(130,857)	0	0	0	0	0	0	0	0	0	0	0	0	0
58	(391.9) Computer & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
59	(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
60	(394) Tools	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
61	(394.1) Tools	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
62	(394.2) Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	(396) Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
64	(397) Communication Equipment	102,489	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	102,489	0
65	(397.2) Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
66	(398) Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
67	Total General Plant	$207,149,193	$164	($49,414)	($13,608,723)	($130,857)	($11,870)	($64,443)	($4,632)	($4,940)	($5,905)	($41,238)	($21,323)	($17,772)	($7,617)	($1,477)	($1,944)	$193,177,204	($5,918,832)
68	Total Orig Cost Plant in Service	$207,149,193	$164	($49,414)	($13,608,723)	($130,857)	($11,870)	($64,443)	($4,632)	($4,940)	($5,905)	($41,238)	($21,323)	($17,772)	($7,617)	($1,477)	($1,944)	$193,177,204	($5,918,832)
69	Allocation Factor to TGS	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%	25.2103%
70	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%
71	Total Allocated Plant In Service	$24,280,047	$19	($5,792)	($1,595,084)	($15,338)	($1,391)	($7,553)	($543)	($579)	($692)	($4,834)	($2,499)	($2,083)	($893)	($173)	($228)	$22,642,384	($693,749)

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve.xlxs

SCHEDULE C-1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$59,925,068	$14,842,596	$74,767,664
2	Allocated TGS Division Completed Construction Not Classified	WKP C-1.b	13,102	1,584,472	1,597,573
3	Allocated Corporate Completed Construction Not Classified	WKP C-1.c	399,529	3,540,861	3,940,390
4	Total Completed Construction Not Classified		$60,337,698	$19,967,929	$80,305,627

WKP C-1.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1060 6/30/2019	MEAL & HOTEL ADJUSTMENTS ACCT 1060 6/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060 6/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCT 1060 6/30/2019	Total Adjusments for TYE 6/30/2019	DIRECT TEST YEAR ADJUSTED ACCT 1060 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	DIRECT ADJUSTED AT 9/30/2019 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	Total Intangible CCNC	$0	$0	$0	$0	$0	$0	$0	$0
	GATHERING AND TRANSMISSION PLANT								
5	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0
8	(329) Other Structures	0	0	0	0	0	0	0	0
9	(332) Field Lines	0	0	0	0	0	0	0	0
10	(333) Field Compressor Station Equip	0	0	0	0	0	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0
12	(336) Purification Equipment	0	0	0	0	0	0	0	0
13	(337) Other Equip	0	0	0	0	0	0	0	0
14	(365) Land & Land Rights	0	0	0	0	0	0	0	0
15	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0
16	(367) Mains	1,316,470	(54)	0	0	(54)	1,316,416	10,867	1,327,284
17	(368) Compressor Station Equip	0	0	0	0	0	0	0	0
18	(369) Measure/Reg. Station Equipment	1,246,488	0	0	0	0	1,246,488	(10,529)	1,235,959
19	(371) Other Equipment	0	0	0	0	0	0	0	0
20	Total Gathering and Transmission CCNC	$2,562,958	($54)	$0	$0	($54)	$2,562,904	$338	$2,563,242
	DISTRIBUTION PLANT								
21	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
22	(374.1) Land & Land Rights	0	0	0	0	0	0	5,715,287	5,715,287

WKP C-1.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1060 6/30/2019	MEAL & HOTEL ADJUSTMENTS ACCT 1060 6/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060 6/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCT 1060 6/30/2019	Total Adjusments for TYE 6/30/2019	DIRECT TEST YEAR ADJUSTED ACCT 1060 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	DIRECT ADJUSTED AT 9/30/2019 ACCT 1060
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
23	(374.2) - Land Rights	1,290	0	0	0	0	1,290	5,685	6,975
24	(375.1) Structures & Improvements	(916)	0	0	0	0	(916)	0	(916)
25	(375.2) Other Distr Systems Struct	916	0	0	0	0	916	11,147	12,063
26	(376) Mains	46,653,057	(2,252)	0	0	(2,252)	46,650,805	2,770,455	49,421,260
27	(376.9) Mains - Cathodic Protection Anodes	85,476	0	0	0	0	85,476	101,019	186,496
28	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0
29	(378) Meas. & Reg. Station - General	2,655,687	(19)	0	0	(19)	2,655,668	1,366,107	4,021,774
30	(379) Meas. & Reg. Station - C.G.	113,440	0	0	0	0	113,440	2	113,443
31	(380) Services	4,687,863	(74)	0	0	(74)	4,687,789	329,121	5,016,910
32	(380.1) Ind Service Line Equip	4,391	0	0	0	0	4,391	4,128	8,519
33	(380.2) Comm Service Line Equip	227,921	0	0	0	0	227,921	22,733	250,655
34	(380.4) Yard Lines-Customer Svc	137,764	0	0	0	0	137,764	64,410	202,174
35	(380.6) Services - Tie-Ins Total	0	0	0	0	0	0	0	0
36	(381) Meters	476,984	0	0	0	0	476,984	786,047	1,263,031
37	(382) Meter Installations	4,764	0	0	0	0	4,764	1,243	6,007
38	(383) House Regulators	58,892	0	0	0	0	58,892	77,083	135,976
39	(385) Indust. Meas. & Reg. Stat. Equipment	838,503	(15)	0	0	(15)	838,488	237,401	1,075,889
40	(386) Other Property on Customer Premises	0	0	0	0	0	0	0	0
41	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0
42	Total Distribution CCNC	$55,946,033	($2,360)	$0	$0	($2,360)	$55,943,673	$11,491,870	$67,435,543
	GENERAL PLANT								
43	(389) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
44	(390) Structures & Improvements	0	0	0	0	0	0	0	0
45	(390.1) Structures & Improvements	199,208	0	0	0	0	199,208	31,288	230,497
46	(390.2) Leasehold Improvements	155,344	0	0	0	0	155,344	546,130	701,474
47	(391) Office Furniture & Equipment	0	0	0	0	0	0	0	0

WKP C-1.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1060 6/30/2019	MEAL & HOTEL ADJUSTMENTS ACCT 1060 6/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060 6/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCT 1060 6/30/2019	Total Adjusments for TYE 6/30/2019	DIRECT TEST YEAR ADJUSTED ACCT 1060 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	DIRECT ADJUSTED AT 9/30/2019 ACCT 1060
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
48	(391.1) Office Furniture & Equipment	236	0	0	0	0	236	105,813	106,049
49	(391.4) Audio Visual Equipment Total	0	0	0	0	0	0	0	0
50	(391.9) Computer & Equipment	0	0	0	0	0	0	18,970	18,970
51	(392) Transportation Equipment	486,842	0	0	0	0	486,842	1,301,159	1,788,001
52	(392.2) Pickup Trucks & Vans	0	0	0	0	0	0	0	0
53	(394) Tools, Shop & Garage	125,917	0	0	0	0	125,917	802,875	928,792
54	(394.1) Tools	1,081	0	0	0	0	1,081	17,859	18,940
55	(395) CNG Equipment	0	0	0	0	0	0	0	0
56	(396) Major Work Equipment	31,688	0	0	0	0	31,688	399,123	430,811
57	(397) Communication Equipment	415,759	0	0	0	0	415,759	129,586	545,345
58	(398) Miscellaneous General Plant	0	0	0	0	0	0	0	0
59	Total General CCNC	$1,416,077	$0	$0	$0	$0	$1,416,077	$3,352,802	$4,768,879
60	Total Orig Cost CCNC	$59,925,068	($2,414)	$0	$0	($2,414)	$59,922,654	$14,845,010	$74,767,664

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC - CGSA.xlsx

WKP C-1.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - POST TEST YEAR SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1060 AT 9/30/2019	Total Adjustment for TYE 6/30/2019	MEALS & HOTEL ADJUSTMENTS ACCT 1060 AT 9/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060 AT 9/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCT 1060 AT 9/30/2019	RECLASSIFICATION TO CORRECT GCSA LOCATION ADJUSTMENT OR RECLASS TO CORRECT FERC ACCT ACCT 1060 AT 9/30/2019	DIRECT ADJUSTED ACCTS 1070 CWIP AT 9/30/2019	DIRECT ADJUSTED ACCT 1060 AT 9/30/2019	TOTAL CHANGE IN ACCT 1060 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	INTANGIBLE PLANT									
1	(301) Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	(302) Franchises & Consents	0	0	0	0	0	0	0	0	0
3	(303) Misc. Intangible	0	0	0	0	0	0	0	0	0
4	Total Intangible CCNC	$0	$0	$0	$0	$0	$0	$0	$0	$0
	GATHERING AND TRANSMISSION PLANT									
5	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0
8	(329) Other Structures	0	0	0	0	0	0	0	0	0
9	(332) Field Lines	0	0	0	0	0	0	0	0	0
10	(333) Field Compressor Station Equip	0	0	0	0	0	0	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0
12	(336) Purification Equipment	0	0	0	0	0	0	0	0	0
13	(337) Other Equip	0	0	0	0	0	0	0	0	0
14	(365) Land & Land Rights	0	0	0	0	0	0	0	0	0
15	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0
16	(367) Mains	1,327,270	(54)	0	0	0	0	67	1,327,284	10,867
17	(368) Compressor Station Equip		0	0	0	0	0	0	0	0
18	(369) Measure/Reg. Station Equipment	1,235,959	0	0	0	0	0	0	1,235,959	(10,529)
19	(371) Other Equipment	0	0	0	0	0	0	0	0	0
20	Total Gathering and Transmission CCNC	$2,563,229	($54)	$0	$0	$0	$0	$67	$2,563,242	$338
	DISTRIBUTION PLANT									
21	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	(374.1) Land & Land Rights	(0)	0	0	0	0	0	5,715,287	5,715,287	5,715,287
23	(374.2) - Land Rights	6,975	0	0	0	0	0	0	6,975	5,685
24	(375.1) Structures & Improvements	(916)	0	0	0	0	0	0	(916)	0
25	(375.2) Other Distr Systems Struct	916	0	0	0	0	0	11,147	12,063	11,147

WKP C-1.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - POST TEST YEAR SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1060 AT 9/30/2019	Total Adjustment for TYE 6/30/2019	MEALS & HOTEL ADJUSTMENTS ACCT 1060 AT 9/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060 AT 9/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCT 1060 AT 9/30/2019	RECLASSIFICATION TO CORRECT GCSA LOCATION ADJUSTMENT OR RECLASS TO CORRECT FERC ACCT ACCT 1060 AT 9/30/2019	DIRECT ADJUSTED ACCTS 1070 CWIP AT 9/30/2019	DIRECT ADJUSTED ACCT 1060 AT 9/30/2019	TOTAL CHANGE IN ACCT 1060 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
26	(376) Mains	48,470,544	(2,252)	0	0	0	0	952,968	49,421,260	2,770,455
27	(376.9) Mains - Cathodic Protection Anodes	183,331	0	0	0	0	0	3,164	186,496	101,019
28	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0	0
29	(378) Meas. & Reg. Station - General	3,038,379	(19)	0	0	0	0	983,414	4,021,774	1,366,107
30	(379) Meas. & Reg. Station - C.G.	113,440	0	0	0	0	0	2	113,443	2
31	(380) Services	4,910,729	(74)	0	0	0	0	106,255	5,016,910	329,121
32	(380.1) Ind Service Line Equip	8,519	0	0	0	0	0	0	8,519	4,128
33	(380.2) Comm Service Line Equip	232,520	0	0	0	0	0	18,134	250,655	22,733
34	(380.4) Yard Lines-Customer Svc	201,151	0	0	0	0	0	1,023	202,174	64,410
35	(380.6) Services - Tie-Ins Total		0	0	0	0	0	0	0	0
36	(381) Meters	1,263,031	0	0	0	0	0	0	1,263,031	786,047
37	(382) Meter Installations	6,007	0	0	0	0	0	0	6,007	1,243
38	(383) House Regulators	135,976	0	0	0	0	0	0	135,976	77,083
39	(385) Indust. Meas. & Reg. Stat. Equipment	1,041,482	(15)	0	0	0	0	34,422	1,075,889	237,401
40	(386) Other Property on Customer Premises	0	0	0	0	0	0	0	0	0
41	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0
42	Total Distribution CCNC	$59,612,086	($2,360)	$0	$0	$0	$0	$7,825,817	$67,435,543	$11,491,870
	GENERAL PLANT									
43	(389) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	(390) Structures & Improvements	0	0	0	0	0	0	0	0	0
45	(390.1) Structures & Improvements	228,617	0	0	0	0	0	1,880	230,497	31,288
46	(390.2) Leasehold Improvements	170,159	0	0	0	0	0	531,315	701,474	546,130
47	(391) Office Furniture & Equipment	0	0	0	0	0	0	0	0	0
48	(391.1) Office Furniture & Equipment	236	0	0	0	0	0	105,813	106,049	105,813
49	(391.4) Audio Visual Equipment Total	0	0	0	0	0	0	0	0	0
50	(391.9) Computer & Equipment	(0)	0	0	0	0	0	18,970	18,970	18,970
51	(392) Transportation Equipment	767,481	0	0	0	0	0	1,020,521	1,788,001	1,301,159
52	(393) Stores Equipment	0	0	0	0	0	0	0	0	0
53	(394) Tools, Shop & Garage	237,349	0	0	0	0	0	691,443	928,792	802,875

WKP C-1.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - POST TEST YEAR SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1060 AT 9/30/2019	Total Adjustment for TYE 6/30/2019	MEALS & HOTEL ADJUSTMENTS ACCT 1060 AT 9/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060 AT 9/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCT 1060 AT 9/30/2019	RECLASSIFICATION TO CORRECT GCSA LOCATION ADJUSTMENT OR RECLASS TO CORRECT FERC ACCT ACCT 1060 AT 9/30/2019	DIRECT ADJUSTED ACCTS 1070 CWIP AT 9/30/2019	DIRECT ADJUSTED ACCT 1060 AT 9/30/2019	TOTAL CHANGE IN ACCT 1060 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
54	(394.1) Tools	20,022	0	0	0	0	0	(1,081)	18,940	17,859
55	(395) CNG Equipment	0	0	0	0	0	0	0	0	0
56	(396) Major Work Equipment	31,688	0	0	0	0	0	399,123	430,811	399,123
57	(397) Communication Equipment	459,093	0	0	0	0	0	86,252	545,345	129,586
58	(398) Miscellaneous General Plant	0	0	0	0	0	0	0	0	0
59	Total General CCNC	$1,914,644	$0	$0	$0	$0	$0	$2,854,235	$4,768,879	$3,352,802
60	Total Orig Cost CCNC	$64,089,959	($2,414)	$0	$0	$0	$0	$10,680,119	$74,767,664	$14,845,010

Source: WKP Ca.1 & C-1a CPR 1 101 & 106 Post TY at Sep_2019.xlsx
Source: WKP C.a.1 & C-1.a 107& 108 Post TY at Sep_2019.xlsx

WKP C-1.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060 AT 6/30/2019	ADJUSTMENT TO INCLUDE CUSTOMER INFO CENTER BUILDING	TGS DIVISION TEST YEAR ADJUSTED ACCT 1060 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	TGS DIVISION ADJUSTED ACCT 1060 AT 9/30/2019
		(a)	(b)	(c)	(d)	(e)
	INTANGIBLE PLANT					
1	(301) Organization	$0	$0	$0	$0	$0
2	(302) Franchises & Consents	0	0	0	0	0
3	(303) Misc. Intangible	0	0	0	0	0
4	Total Intangible Plant	$0	$0	$0	$0	$0
	GATHERING AND TRANSMISSION PLANT					
5	(325) Land & Land Rights	$0	$0	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0
8	(329) Other Structures	0	0	0	0	0
9	(332) Field Lines	0	0	0	0	0
10	(333) Field Compressor Station Equip	0	0	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0
12	(336) Purification Equipment	0	0	0	0	0
13	(337) Other Equip	0	0	0	0	0
14	(365) Land & Land Rights	0	0	0	0	0
15	(366) Meas/Reg Station Structures	0	0	0	0	0
16	(367) Mains	0	0	0	0	0
17	(368) Compressor Station Equip	0	0	0	0	0
18	(369) Measure/Reg. Station Equipment	0	0	0	0	0
19	(371) Other Equipment	0	0	0	0	0
20	Total Gathering and Transmission Plant	$0	$0	$0	$0	$0
	DISTRIBUTION PLANT					
21	(374) Land & Land Rights	$0	$0	$0	$0	$0
22	(375.1) Structures & Improvements	0	0	0	0	0
23	(375.2) Other Distr Systems Struct	0	0	0	0	0
24	(376) Mains	0	0	0	0	0
25	(376.9) Mains - Cathodic Protection Anodes	0	0	0	0	0
26	(377) Compressor Station Equipment	0	0	0	0	0
27	(378) Meas. & Reg. Station - General	0	0	0	0	0
28	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0
29	(380) Services	0	0	0	0	0
30	(380.1) Ind Service Line Equip	0	0	0	0	0
31	(380.2) Comm Service Line Equip	0	0	0	0	0
32	(380.4) Yard Lines-Customer Svc	0	0	0	0	0
33	(381) Meters	0	0	0	0	0
34	(382) Meter Installations	0	0	0	0	0
35	(383) House Regulators	0	0	0	0	0
36	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0
37	(386) Other Property on Customer Premises	0	0	0	0	0
38	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0
39	Total Distribution CCNC	$0	$0	$0	$0	$0

WKP C-1.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060 AT 6/30/2019	ADJUSTMENT TO INCLUDE CUSTOMER INFO CENTER BUILDING	TGS DIVISION TEST YEAR ADJUSTED ACCT 1060 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	TGS DIVISION ADJUSTED ACCT 1060 AT 9/30/2019
		(a)	(b)	(c)	(d)	(e)
	GENERAL PLANT					
40	(389) Land & Land Rights	$0	$527,777	$527,777	$0	$527,777
41	(390.1) Structures & Improvements	0	2,908,374	2,908,374	0	2,908,374
42	(390.2) Leasehold Equipment	28,180	0	28,180	(28,180)	0
43	(391.1) Office Furniture & Fixtures	0	0	0	0	0
44	(391.2) Data Processing Equipment	0	0	0	0	0
45	(391.3) Office Machines	0	0	0	0	0
46	(391.4) Audio Visual Equipment	0	0	0	0	0
47	(391.6) Purchased Software	0	0	0	0	0
48	(391.9) Computer & Equipment	0	0	0	0	0
49	(392.6) Aircraft	0	0	0	0	0
50	(394) Tools	0	0	0	0	0
51	(394.1) Tools	0	0	0	0	0
52	(394.2) Shop Equipment	0	0	0	0	0
53	(396) Major Work Equipment	0	0	0	0	0
54	(397) Communication Equipment	0	0	0	0	0
55	(398) Miscellaneous General Plant	0	0	0	0	0
56	Total General plant	$28,180	$3,436,151	$3,464,331	($28,180)	$3,436,151
57	Total Orig Cost Plant in Service	$28,180	$3,436,151	$3,464,331	($28,180)	$3,436,151
58	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%
59	Total Allocated CCNC	$13,102	$1,597,573	$1,610,675	($13,102)	$1,597,573

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve.xlxs

WKP C-1.b.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - POST TEST YEAR TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060 AT 9/30/2019	ADJUSTMENT TO INCLUDE CUSTOMER INFO CENTER BUILDING	TGS DIVISION TEST YEAR ADJUSTED ACCT 1060 AT 9/30/2019	TOTAL CHANGE IN ACCT 1060 FROM 6/30/2019 TO 9/30/2019
		(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	Total Intangible Plant	$0	$0	$0	$0
	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	0	0	0	0
17	(368) Compressor Station Equip	0	0	0	0
18	(369) Measure/Reg. Station Equipment	0	0	0	0
19	(371) Other Equipment	0	0	0	0
20	Total Gathering and Transmission Plant	$0	$0	$0	$0
	DISTRIBUTION PLANT				
21	(374) Land & Land Rights	$0	$0	$0	$0
22	(375.1) Structures & Improvements	0	0	0	0
23	(375.2) Other Distr Systems Struct	0	0	0	0
24	(376) Mains	0	0	0	0
25	(376.9) Mains - Cathodic Protection Anodes	0	0	0	0
26	(377) Compressor Station Equipment	0	0	0	0
27	(378) Meas. & Reg. Station - General	0	0	0	0
28	(379) Meas. & Reg. Station - C.G.	0	0	0	0
29	(380) Services	0	0	0	0
30	(380.1) Ind Service Line Equip	0	0	0	0
31	(380.2) Comm Service Line Equip	0	0	0	0
32	(380.4) Yard Lines-Customer Svc	0	0	0	0
33	(381) Meters	0	0	0	0
34	(382) Meter Installations	0	0	0	0
35	(383) House Regulators	0	0	0	0
36	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0
37	(386) Other Property on Customer Premises	0	0	0	0
38	(387) Meas. & Reg. Stat. Equipment	0	0	0	0
39	Total Distribution CCNC	$0	$0	$0	$0

WKP C-1.b.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - POST TEST YEAR TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060 AT 9/30/2019	ADJUSTMENT TO INCLUDE CUSTOMER INFO CENTER BUILDING	TGS DIVISION TEST YEAR ADJUSTED ACCT 1060 AT 9/30/2019	TOTAL CHANGE IN ACCT 1060 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)
	GENERAL PLANT				
40	(389) Land & Land Rights	$0	$527,777	$527,777	$0
41	(390.1) Structures & Improvements	0	2,908,374	2,908,374	0
42	(390.2) Leasehold Equipment	0	0	0	(28,180)
43	(391.1) Office Furniture & Fixtures	0	0	0	0
44	(391.2) Data Processing Equipment	0	0	0	0
45	(391.3) Office Machines	0	0	0	0
46	(391.4) Audio Visual Equipment	0	0	0	0
47	(391.6) Purchased Software	0	0	0	0
48	(391.9) Computer & Equipment	0	0	0	0
49	(392.6) Aircraft	0	0	0	0
50	(394) Tools	0	0	0	0
51	(394.1) Tools	0	0	0	0
52	(394.2) Shop Equipment	0	0	0	0
53	(396) Major Work Equipment	0	0	0	0
54	(397) Communication Equipment	0	0	0	0
55	(398) Miscellaneous General Plant	0	0	0	0
56	Total General plant	$0	$3,436,151	$3,436,151	($28,180)
57	Total Orig Cost Plant in Service	$0	$3,436,151	$3,436,151	($28,180)
58	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%
59	Total Allocated CCNC	$0	$1,597,573	$1,597,573	($13,102)

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve.xlxs

WKP C-1.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK Acct 1060 AT 6/30/2019	REMOVE MEALS & HOTEL	CORPORATE TEST YEAR ADJUSTED Acct 1060 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	CORPORATE ADJUSTED ACCT 1060 AT 9/30/2019	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	INTANGIBLE PLANT							
1	(301) Organization	$0	$0	$0	$0	$0		
2	(302) Franchises & Consents	0	0	0	0	0		
3	(303) Misc. Intangible	0	0	0	0	0		
4	Total Intangible Plant	$0	$0	$0	$0	$0		
	GATHERING AND TRANSMISSION PLANT							
5	(325) Land & Land Rights	$0	$0	$0	$0	$0		
6	(327) Field Comprss Station Strucutres	0	0	0	0	0		
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0		
8	(329) Other Structures	0	0	0	0	0		
9	(332) Field Lines	0	0	0	0	0		
10	(333) Field Compressor Station Equip	0	0	0	0	0		
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0		
12	(336) Purification Equipment	0	0	0	0	0		
13	(337) Other Equip	0	0	0	0	0		
14	(365) Land & Land Rights	0	0	0	0	0		
15	(366) Meas/Reg Station Structures	0	0	0	0	0		
16	(367) Mains	0	0	0	0	0		
17	(368) Compressor Station Equip	0	0	0	0	0		
18	(369) Measure/Reg. Station Equipment	0	0	0	0	0		
19	(371) Other Equipment	0	0	0	0	0		
20	Total Gathering and Transmission Plant	$0	$0	$0	$0	$0		
	DISTRIBUTION PLANT							
21	(374) Land & Land Rights	$0	$0	$0	$0	$0		
22	(375.1) Structures & Improvements	0	0	0	0	0		
23	(375.2) Other Distr Systems Struct	0	0	0	0	0		
24	(376) Mains	0	0	0	0	0		
25	(376.9) Mains - Cathodic Protection Anodes	0	0	0	0	0		
26	(377) Compressor Station Equipment	0	0	0	0	0		
27	(378) Meas. & Reg. Station - General	0	0	0	0	0		
28	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0		
29	(380) Services	0	0	0	0	0		
30	(380.1) Ind Service Line Equip	0	0	0	0	0		
31	(380.2) Comm Service Line Equip	0	0	0	0	0		
32	(380.4) Yard Lines-Customer Svc	0	0	0	0	0		
33	(381) Meters	0	0	0	0	0		
34	(382) Meter Installations	0	0	0	0	0		
35	(383) House Regulators	0	0	0	0	0		
36	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0		
37	(386) Other Property on Customer Premises	0	0	0	0	0		
38	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0		
39	Total Distribution CCNC	$0	$0	$0	$0	$0		

WKP C-1.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK Acct 1060 AT 6/30/2019	REMOVE MEALS & HOTEL	CORPORATE TEST YEAR ADJUSTED Acct 1060 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 9/30/2019	CORPORATE ADJUSTED ACCT 1060 AT 9/30/2019	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	GENERAL PLANT							
40	(389) Land & Land Rights	$0	$0	$0	$0	$0	25.01%	$0
41	(390.1) Structures & Improvements	0	0	0	0	0	25.01%	0
42	(390.2) Leasehold Improvements	0	0	0	348,555	348,555	25.01%	87,174
43	(391.1) Office Furniture & Equipment	0	0	0	0	0	25.01%	0
44	(391.19) Airplane Hanger Furniture	0	0	0	0	0	25.01%	0
45	(391.2) Data Processing Equipment	0	0	0	0	0	25.01%	0
46	(391.3) Office Machines	0	0	0	0	0	25.01%	0
47	(391.4) Audio Visual Equipment	0	0	0	0	0	25.01%	0
48	(391.5) Artwork	0	0	0	0	0	25.01%	0
49	(391.6) Purchased Software	3,435,942	(155)	3,435,787	29,902,808	33,338,595	25.01%	8,337,982
50	(391.6) Banner Software	0	0	0	0	0	30.41%	0
51	(391.6) PowerPlant System	0	0	0	0	0	24.02%	0
52	(391.6) Riskworks	0	0	0	0	0	0.00%	0
53	(391.6) Maximo	0	0	0	0	0	24.71%	0
54	(391.6) Dynamic Risk Assessment	0	0	0	0	0	0.00%	0
55	(391.6) Concur Project	0	0	0	0	0	27.95%	0
56	(391.6) Journey-Employee-ODC Distrigas	0	0	0	0	0	25.01%	0
57	(391.6) Journey-Employee Count	0	0	0	0	0	27.95%	0
58	(391.6) Ariba Software	0	0	0	0	0	30.96%	0
59	(391.6) Accounts Payable Software	0	0	0	0	0	30.96%	0
60	(391.8) Micro Computer Software	0	0	0	200,152	200,152	25.01%	50,058
61	(391.81) Aircraft Computer Equipment	0	0	0	0	0	25.01%	0
62	(391.9) Computer & Equipment	0	0	0	0	0	25.01%	0
63	(392.6) Aircraft	0	0	0	0	0	25.01%	0
64	(394.) Tools	0	0	0	0	0	25.01%	0
65	(394.1) Tools	0	0	0	0	0	25.01%	0
66	(394.2) Shop Equipment	0	0	0	0	0	25.01%	0
67	(396) Major Work Equipment	0	0	0	0	0	25.01%	0
68	(397) Communication Equipment	0	0	0	0	0	25.01%	0
69	(397.2) Telephone Equipment	0	0	0	0	0	25.01%	0
70	(398) Miscellaneous General Plant	0	0	0	0	0	25.01%	0
71	Total General plant	$3,435,942	($155)	$3,435,787	$30,451,515	$33,887,301	25.01%	$8,475,214
72	Total Orig Cost Plant in Service	$3,435,942	($155)	$3,435,787	$30,451,515	$33,887,301		
73	Allocation Factor to TGS	25.0100%	25.0100%	25.0100%	25.0100%	25.0100%		
74	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%		
75	Total Allocated CCNC	$399,529	($18)	$399,511	$3,540,879	$3,940,390		

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve.xlxs

WKP C-1.c.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - POST TEST YEAR CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK Acct 1060 AT 9/30/2019	REMOVE MEALS & HOTEL	CORP ADJUSTED ACCTS 1070 CWIP AT 9/30/2019	CORPORATE ADJUSTED ACCT 1060 AT 9/30/2019	TOTAL CHANGE IN ACCT 1060 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)
	INTANGIBLE PLANT					
1	(301) Organization	$0	$0	$0	$0	$0
2	(302) Franchises & Consents	0	0	0	0	0
3	(303) Misc. Intangible	0	0	0	0	0
4	Total Intangible Plant	$0	$0	$0	$0	$0
	GATHERING AND TRANSMISSION PLANT					
5	(325) Land & Land Rights	$0	$0	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0
8	(329) Other Structures	0	0	0	0	0
9	(332) Field Lines	0	0	0	0	0
10	(333) Field Compressor Station Equip	0	0	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0
12	(336) Purification Equipment	0	0	0	0	0
13	(337) Other Equip	0	0	0	0	0
14	(365) Land & Land Rights	0	0	0	0	0
15	(366) Meas/Reg Station Structures	0	0	0	0	0
16	(367) Mains	0	0	0	0	0
17	(368) Compressor Station Equip	0	0	0	0	0
18	(369) Measure/Reg. Station Equipment	0	0	0	0	0
19	(371) Other Equipment	0	0	0	0	0
20	Total Gathering and Transmission Plant	$0	$0	$0	$0	$0
	DISTRIBUTION PLANT					
21	(374) Land & Land Rights	$0	$0	$0	$0	$0
22	(375.1) Structures & Improvements	0	0	0	0	0
23	(375.2) Other Distr Systems Struct	0	0	0	0	0
24	(376) Mains	0	0	0	0	0
25	(376.9) Mains - Cathodic Protection Anodes	0	0	0	0	0
26	(377) Compressor Station Equipment	0	0	0	0	0
27	(378) Meas. & Reg. Station - General	0	0	0	0	0
28	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0
29	(380) Services	0	0	0	0	0
30	(380.1) Ind Service Line Equip	0	0	0	0	0
31	(380.2) Comm Service Line Equip	0	0	0	0	0
32	(380.4) Yard Lines-Customer Svc	0	0	0	0	0
33	(381) Meters	0	0	0	0	0
34	(382) Meter Installations	0	0	0	0	0
35	(383) House Regulators	0	0	0	0	0
36	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0
37	(386) Other Property on Customer Premises	0	0	0	0	0
38	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0
39	Total Distribution CCNC	$0	$0	$0	$0	$0

WKP C-1.c.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED - POST TEST YEAR CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK Acct 1060 AT 9/30/2019	REMOVE MEALS & HOTEL	CORP ADJUSTED ACCTS 1070 CWIP AT 9/30/2019	CORPORATE ADJUSTED ACCT 1060 AT 9/30/2019	TOTAL CHANGE IN ACCT 1060 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)
	GENERAL PLANT					
40	(389) Land & Land Rights	$0	$0	$0	$0	$0
41	(390.1) Structures & Improvements	0	0	0	0	0
42	(390.2) Leasehold Improvements	46,575	0	301,980	348,555	348,555
43	(391.1) Office Furniture & Equipment	0	0	0	0	0
44	(391.19) Airplane Hanger Furniture	0	0	0	0	0
45	(391.2) Data Processing Equipment	0	0	0	0	0
46	(391.3) Office Machines	0	0	0	0	0
47	(391.4) Audio Visual Equipment	0	0	0	0	0
48	(391.5) Artwork	0	0	0	0	0
49	(391.6) Purchased Software	12,848,255	0	20,490,339	33,338,595	29,902,808
50	(391.6) Banner Software	0	0	0	0	0
51	(391.6) PowerPlant System	0	0	0	0	0
52	(391.6) Riskworks	0	0	0	0	0
53	(391.6) Maximo	0	0	0	0	0
54	(391.6) Dynamic Risk Assessment	0	0	0	0	0
55	(391.6) Concur Project	0	0	0	0	0
56	(391.6) Journey-Employee-ODC Distrigas	0	0	0	0	0
57	(391.6) Journey-Employee Count	0	0	0	0	0
58	(391.6) Ariba Software	0	0	0	0	0
59	(391.6) Accounts Payable Software	0	0	0	0	0
60	(391.8) Micro Computer Software	0	0	200,152	200,152	200,152
61	(391.81) Aircraft Computer Equipment	0	0	0	0	0
62	(391.9) Computer & Equipment	0	0	0	0	0
63	(392.6) Aircraft	0	0	0	0	0
64	(394.) Tools	0	0	0	0	0
65	(394.1) Tools	0	0	0	0	0
66	(394.2) Shop Equipment	0	0	0	0	0
67	(396) Major Work Equipment	0	0	0	0	0
68	(397) Communication Equipment	0	0	0	0	0
69	(397.2) Telephone Equipment	0	0	0	0	0
70	(398) Miscellaneous General Plant	0	0	0	0	0
71	Total General plant	$12,894,830	$0	$20,992,472	$33,887,301	$30,451,515
72	Total Orig Cost Plant in Service	$12,894,830	$0	$20,992,472	$33,887,301	$30,451,515
73	Allocation Factor to TGS	25.0100%	25.0100%	25.0100%	25.0100%	25.0100%
74	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%
75	Total Allocated CCNC	$1,499,401	$0	$2,440,989	$3,940,390	$3,540,879

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve.xlxs

SCHEDULE D

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	($177,705,899)	$4,778,322	($172,927,577)
2	Allocated TGS Division Accumulated Reserves	WKP D.b	(125,324)	(1,253,203)	(1,378,527)
3	Allocated Corporate Accumulated Reserves	WKP D.c	(9,404,053)	1,527,392	(7,876,661)
4	Total Accumulated Reserves		($187,235,275)	$5,052,510	($182,182,765)

WKP D.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1080100 DEPR 6/30/2019	DIRECT PER BOOK ACCT 1110 AMORT 6/30/2019	DIRECT PER BOOK ACCTS 1080100 & 1110 6/30/2019	2015 RESERVE REBALANCE ADJUSTMENT 6/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCTS 1080100 & 1110 6/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCTS 1080100 & 1110 6/30/2019	REMOVAL OF RETIRING ASSETS 6/30/2019	Addition of OPC High Pressure Distribution Line 6/30/2019	2019 RESERVE REBALANCE ADJUSTMENT 6/30/2019	Total Adjusments for TYE 6/30/2019	DIRECT TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVE CHANGES AS OF 9/30/2019	DIRECT ADJUSTED ACCTS 1080100 & 1110 AT 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	INTANGIBLE PLANT													
1	(301) Organization	($43,615)	$0	($43,615)	$0	$0	$0	$0	$0	$0	$0	($43,615)	($563)	($44,178)
2	(301) Organization- OPC	0	0	0	0	0	0	0	(726)	0	(726)	(726)	(22)	(748)
3	(302) Franchises & Consents	(394,901)	0	(394,901)	0	0	0	0	0	0	0	(394,901)	0	(394,901)
4	(303) Misc. Intangible	0	(723,661)	(723,661)	0	0	0	0	0	0	0	(723,661)	(296)	(723,957)
5	(303) Misc. Intangible - OPC	0	0	0	0	0	0	0	(14,336)	0	(14,336)	(14,336)	0	(14,336)
6	(303.1) Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Intangible Plant Reserves	(438,516)	($723,661)	($1,162,177)	$0	$0	$0	$0	($15,062)	$0	($15,062)	($1,177,239)	($880)	($1,178,119)
	GATHERING AND TRANSMISSION PLANT													
8	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0	0
10	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0
11	(329) Other Structures	0	0	0	0	0	0	0	0	0	0	0	0	0
12	(332) Field Lines	0	0	0	0	0	0	0	0	0	0	0	0	0
13	(333) Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0
14	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
15	(336) Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
16	(337) Other Equip	0	0	0	0	0	0	0	0	0	0	0	0	0
17	(365) Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0
18	(365.1) Land-OPC	0	0	0	0	0	0	0	0	0	0	0	0	0
19	(365.2) Rights of Way-OPC	0	0	0	0	0	0	0	(2,124)	0	(2,124)	(2,124)	(8)	(2,132)
20	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0
21	(366.1) Compressor Station Structure -OPC	0	0	0	0	0	0	0	(2,346)	0	(2,346)	(2,346)	0	(2,346)
22	(367) Mains	(1,610,512)	0	(1,610,512)	0	0	0	0	0	0	0	(1,610,512)	857,311	(753,201)
23	(367) Mains - OPC	0	0	0	0	0	0	0	(2,327,213)	0	(2,327,213)	(2,327,213)	(32,131)	(2,359,343)
24	(368) Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0
25	(369) Measure/Reg. Station Equipment	(67,538)	0	(67,538)	0	0	0	0	0	0	0	(67,538)	166,444	98,906
26	(369) Measure/Reg. Station Equipment - OPC	0	0	0	0	0	0	0	(63,476)	0	(63,476)	(63,476)	(994)	(64,469)
27	(369.1) Measuring Station Equipment - OPC	0	0	0	0	0	0	0	(537,229)	0	(537,229)	(537,229)	(5,310)	(542,539)
28	(371) Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
29	(371) Other Equipment - OPC	0	0	0	0	0	0	0	(11,056)	0	(11,056)	(11,056)	(300)	(11,357)
30	Total Gathering and Transmission Plant Reserves	(1,678,050)	$0	($1,678,050)	$0	$0	$0	$0	($2,943,443)	$0	($2,943,443)	($4,621,493)	$985,012	($3,636,481)
	DISTRIBUTION PLANT													
31	(374) Land & Land Rights	($255)	$0	($255)	$0	$0	$0	$0	$0	$0	$0	($255)	$0	($255)
32	(374.2) Land & Land Rights	(9,440)	0	(9,440)	0	0	0	0	0	0	0	(9,440)	0	(9,440)
33	(375) Structures & Improvements	(23,544)	0	(23,544)	0	0	0	0	0	0	0	(23,544)	(210)	(23,755)
34	(375.1) Structures & Improvements	(5,429)	0	(5,429)	0	0	0	0	0	0	0	(5,429)	(67)	(5,495)
35	(375.2) Other Distr Systems Struct	33,509	0	33,509	0	0	0	0	0	0	0	33,509	(29)	33,479
36	(376) Mains	(67,846,806)	0	(67,846,806)	0	0	242	0	0	0	242	(67,846,564)	4,282,994	(63,563,570)
37	(376.9) Mains - Cathodic Protection Anodes	(10,082,549)	0	(10,082,549)	0	0	0	1,155,062	0	0	1,155,062	(8,927,487)	(455,838)	(9,383,325)
38	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
39	(378) Meas. & Reg. Station - General	(2,703,290)	0	(2,703,290)	0	0	0	0	0	0	0	(2,703,290)	(24,761)	(2,728,050)
40	(379) Meas. & Reg. Station - C.G.	(685,407)	0	(685,407)	0	0	0	0	0	0	0	(685,407)	(10,087)	(695,494)
41	(380) Services	(36,912,574)	0	(36,912,574)	0	367	(30,583)	0	0	0	(30,216)	(36,942,790)	(75,233)	(37,018,022)
42	(381) Meters	(24,368,079)	0	(24,368,079)	0	61	0	0	0	0	61	(24,368,018)	(520,343)	(24,888,362)
43	(382) Meter Installations	(10,137)	0	(10,137)	0	0	0	0	0	0	0	(10,137)	(66)	(10,203)
44	(383) House Regulators	(3,930,574)	0	(3,930,574)	0	32	0	0	0	0	32	(3,930,542)	(46,451)	(3,976,993)
45	(385) Indust. Meas. & Reg. Stat. Equipment	(4,329,098)	0	(4,329,098)	0	143	(3,279)	0	0	0	(3,137)	(4,332,235)	11,364	(4,320,871)
46	(386) Other Property on Customer Premises	(1,056,480)	0	(1,056,480)	0	0	0	0	0	0	0	(1,056,480)	2,153	(1,054,327)
47	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
48	Total Distribution Plant Reserves	(151,930,151)	$0	($151,930,151)	$0	$603	($33,620)	$1,155,062	$0	$0	$1,122,044	($150,808,107)	$3,163,425	($147,644,682)
	GENERAL PLANT													
49	(389) Land & Land Rights	3,573	$0	$3,573	$0	$0	$0	$0	$0	$0	$0	$3,573	$0	$3,573
50	(390) Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0
51	(390.1) Structures & Improvements	(2,757,151)	0	(2,757,151)	992,539	0	0	0	0	422,703	1,415,242	(1,341,909)	(21,748)	(1,363,657)
52	(390.2) Structures & Improvements	0	(961,505)	(961,505)	0	0	0	0	0	0	0	(961,505)	(62,225)	(1,023,730)
53	(391) Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0
54	(391.1) Office Furniture & Equipment	(499,178)	0	(499,178)	0	0	0	0	0	0	0	(499,178)	(10,888)	(510,066)
55	(391.1) Office Furniture & Fixt - OPC	0	0	0	0	0	0	0	(14,671)	0	(14,671)	(14,671)	0	(14,671)

WKP D.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1080100 DEPR 6/30/2019	DIRECT PER BOOK ACCT 1110 AMORT 6/30/2019	DIRECT PER BOOK ACCTS 1080100 & 1110 6/30/2019	2015 RESERVE REBALANCE ADJUSTMENT 6/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCTS 1080100 & 1110 6/30/2019	MISCODED RETIREMENTS ADJUSTMENT ACCTS 1080100 & 1110 6/30/2019	REMOVAL OF RETIRING ASSETS 6/30/2019	Addition of OPC High Pressure Distribution Line 6/30/2019	2019 RESERVE REBALANCE ADJUSTMENT 6/30/2019	Total Adjusments for TYE 6/30/2019	DIRECT TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVE CHANGES AS OF 9/30/2019	DIRECT ADJUSTED ACCTS 1080100 & 1110 AT 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
56	(391.9) Computer & Equipment	(3,615,472)	0	(3,615,472)	0	0	0	2,039,341	0	0	2,039,341	(1,576,132)	(16,452)	(1,592,584)
57	(392) Transportation Equipment	(4,453,397)	0	(4,453,397)	0	0	0	0	0	0	0	(4,453,397)	(441,767)	(4,895,163)
58	(393) Stores Equipment	(7,854)	0	(7,854)	0	0	0	0	0	0	0	(7,854)	(147)	(8,001)
59	(394) Tools, Shop & Garage	(2,539,633)	0	(2,539,633)	0	0	0	0	0	0	0	(2,539,633)	(101,673)	(2,641,307)
60	(394.1) Tools, Shop & Garage - OPC	0	0	0	0	0	0	0	(483)	0	(483)	(483)	(90,000)	(90,483)
61	(395) CNG Equipment	37,480	0	37,480	0	0	0	0	0	0	0	37,480	0	37,480
62	(396) Major Work Equipment	(825,705)	0	(825,705)	0	8,238	0	0	0	0	8,238	(817,467)	71,369	(746,098)
63	(397) Communication Equipment	(7,238,689)	0	(7,238,689)	0	0	0	0	0	0	0	(7,238,689)	(304,738)	(7,543,427)
64	(398) Miscellaneous General Plant	(77,989)	0	(77,989)	0	0	0	0	0	0	0	(77,989)	(2,173)	(80,161)
65	Total General Plant Reserves	(21,974,015)	($961,505)	($22,935,520)	$992,539	$8,238	$0	$2,039,341	($15,154)	$422,703	$3,447,666	($19,487,854)	($980,441)	($20,468,295)
66	Total Accumulated Reserves For Depreciation	(176,020,733)	($1,685,166)	($177,705,899)	$992,539	$8,841	($33,620)	$3,194,402	($2,973,659)	$422,703	$1,611,206	($176,094,693)	$3,167,116	($172,927,577)

Source: WKP C.a and WKP C-1.a_D.a Accum Depr and Amort Adjustment Jun 30 2019_CGSA
Source: WKP D.a CGSA REG BKS_091_PP Rpt_1080100_1080500_Accum Dep Jun 30 2019.xlsx
Source: WKP D.a CGSA REG BKS_091_PP Rpt_1110100_1110500_Accum Amor_Jun 30 2019.xlsx

WKP D.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - POST TEST YEAR DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1080100 DEPR AT 9/30/2019	DIRECT PER BOOK ACCT 1110 AMORT AT 9/30/2019	DIRECT PER BOOK ACCTS 1080100 & 1110 AT 9/30/2019	Total Adjustment for TYE 6/30/2019	ADDITIONAL DEPRECIATION JULY-SEPT 2019 ON ADJUSTMENTS AT 9/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1080100 & 1110 AT 9/30/2019	MISCODED RETIREMENTS ADJUSTMENTACCT 1080100 & 1110 AT 9/30/2019	REMOVAL OF RETIRING ASSETS for Jul-Sep 2019	RECLASSIFICATION TO CORRECT CGSA LOCATION ADJUSTMENT ACCT 1080100 & 1110 AT 9/30/2019	RWIP (RETIREMENT WORK IN PROGRESS) PER BOOK ACCT 1080000 AT 9/30/2019	DIRECT ADJUSTED ACCTS 1080100 & 1110 AT 9/30/2019	TOTAL CHANGE IN ACCTS 1080100 & 1110 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	INTANGIBLE PLANT												
1	(301) Organization	($44,178)	$0	($44,178)	$0	$0	$0	$0	$0	$0	$0	($44,178)	($563)
2	(301) Organization- OPC	0	0	0	(726)	(22)	0	0	0	0	0	(748)	(22)
3	(302) Franchises & Consents	(394,901)	0	(394,901)	0	0	0	0	0	0	0	(394,901)	0
4	(303) Misc. Intangible	0	(723,957)	(723,957)	0	0	0	0	0	0	0	(723,957)	(296)
5	(303) Misc. Intangible - OPC	0	0	0	(14,336)	0	0	0	0	0	0	(14,336)	0
6	(303.1) Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Intangible Plant Reserves	($439,079)	($723,957)	($1,163,036)	($15,062)	($22)	$0	$0	$0	$0	$0	($1,178,119)	($880)
	GATHERING AND TRANSMISSION PLANT												
8	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0
10	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0
11	(329) Other Structures	0	0	0	0	0	0	0	0	0	0	0	0
12	(332) Field Lines	0	0	0	0	0	0	0	0	0	0	0	0
13	(333) Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0
14	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0
15	(336) Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0
16	(337) Other Equip	0	0	0	0	0	0	0	0	0	0	0	0
17	(365) Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0
18	(365.1) Land-OPC	0	0	0	0	0	0	0	0	0	0	0	0
19	(365.2) Rights of Way-OPC	0	0	0	(2,124)	(8)	0	0	0	0	0	(2,132)	(8)
20	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0
21	(366.1) Compressor Station Stru-OPC	0	0	0	(2,346)	0	0	0	0	0	0	(2,346)	0
22	(367) Mains	(861,585)	0	(861,585)	0	0	0	0	0	0	108,383	(753,201)	857,311
23	(367) Mains-OPC	0	0	0	(2,327,213)	(32,131)	0	0	0	0	0	(2,359,343)	(32,131)
24	(368) Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0
25	(369) Measure/Reg. Station Equipment	(80,032)	0	(80,032)	0	0	0	0	0	0	178,938	98,906	166,444
26	(369) Measuring & Regulating-OPC	0	0	0	(63,476)	(994)	0	0	0	0	0	(64,469)	(994)
27	(369.1) Measuring Station Equip-OPC	0	0	0	(537,229)	(5,310)	0	0	0	0	0	(542,539)	(5,310)
28	(371) Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0
29	(371) Other Transmission Eq-OPC	0	0	0	(11,056)	(300)	0	0	0	0	0	(11,357)	(300)
30	Total Gathering and Transmission Plant Reserves	($941,616)	$0	($941,616)	($2,943,443)	($38,743)	$0	$0	$0	$0	$287,321	($3,636,481)	$985,012
	DISTRIBUTION PLANT												
31	(374) Land & Land Rights	($255)	$0	($255)	$0	$0	$0	$0	$0	$0	$0	($255)	$0
32	(374.2) Land & Land Rights	(9,440)	0	(9,440)	0	0	0	0	0	0	0	(9,440)	0
33	(375) Structures & Improvements	(23,755)	0	(23,755)	0	0	0	0	0	0	0	(23,755)	(210)
34	(375.1) Structures & Improvements	(5,495)	0	(5,495)	0	0	0	0	0	0	0	(5,495)	(67)
35	(375.2) Other Distr Systems Struct	33,479	0	33,479	0	0	0	0	0	0	0	33,479	(29)
36	(376) Mains	(69,091,246)	0	(69,091,246)	242	1	0	0	0	0	5,527,433	(63,563,570)	4,282,994
37	(376.9) Mains - Cathodic Protection Anodes	(10,410,347)	0	(10,410,347)	1,155,062	(19,251)	0	0	(108,789)	0	0	(9,383,325)	(455,838)
38	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0
39	(378) Meas. & Reg. Station - General	(2,770,311)	0	(2,770,311)	0	0	0	0	0	0	42,260	(2,728,050)	(24,761)
40	(379) Meas. & Reg. Station - C.G.	(697,312)	0	(697,312)	0	0	0	0	0	0	1,818	(695,494)	(10,087)
41	(380) Services	(37,379,560)	0	(37,379,560)	(30,216)	(193)	0	0	0	0	391,946	(37,018,022)	(75,233)
42	(381) Meters	(24,980,629)	0	(24,980,629)	61	1	0	0	0	0	92,206	(24,888,362)	(520,343)
43	(382) Meter Installations	(10,203)	0	(10,203)	0	0	0	0	0	0	0	(10,203)	(66)
44	(383) House Regulators	(3,978,148)	0	(3,978,148)	32	0	0	0	0	0	1,123	(3,976,993)	(46,451)
45	(385) Indust. Meas. & Reg. Stat. Equipment	(4,396,562)	0	(4,396,562)	(3,137)	(17)	0	0	0	0	78,845	(4,320,871)	11,364
46	(386) Other Property on Customer Premises	(1,054,327)	0	(1,054,327)	0	0	0	0	0	0	0	(1,054,327)	2,153
47	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0
48	Total Distribution Plant Reserves	($154,774,111)	$0	($154,774,111)	$1,122,044	($19,459)	$0	$0	($108,789)	$0	$6,135,631	($147,644,682)	$3,163,425
	GENERAL PLANT												
49	(389) Land & Land Rights	$3,573	$0	$3,573	$0	$0	$0	$0	$0	$0	$0	$3,573	$0
50	(390) Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0
51	(390.1) Structures & Improvements	(2,778,899)	0	(2,778,899)	1,415,242	0	0	0	0	0	0	(1,363,657)	(21,748)
52	(390.2) Structures & Improvements	0	(1,023,730)	(1,023,730)	0	0	0	0	0	0	0	(1,023,730)	(62,225)
53	(391) Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	0
54	(391.1) Office Furniture & Equipment	(510,066)	0	(510,066)	0	0	0	0	0	0	0	(510,066)	(10,888)
55	(391.1) Office Furniture & Fixt - OPC	0	0	0	(14,671)	0	0	0	0	0	0	(14,671)	0
56	(391.9) Computer & Equipment	(3,704,758)	0	(3,704,758)	2,039,341	72,834	0	0	0	0	0	(1,592,584)	(16,452)

WKP D.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - POST TEST YEAR DIRECT

LINE NO.	DESCRIPTION	DIRECT PER BOOK ACCT 1080100 DEPR AT 9/30/2019	DIRECT PER BOOK ACCT 1110 AMORT AT 9/30/2019	DIRECT PER BOOK ACCTS 1080100 & 1110 AT 9/30/2019	Total Adjustment for TYE 6/30/2019	ADDITIONAL DEPRECIATION JULY-SEPT 2019 ON ADJUSTMENTS AT 9/30/2019	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1080100 & 1110 AT 9/30/2019	MISCODED RETIREMENTS ADJUSTMENTACCT 1080100 & 1110 AT 9/30/2019	REMOVAL OF RETIRING ASSETS for Jul-Sep 2019	RECLASSIFICATION TO CORRECT CGSA LOCATION ADJUSTMENT ACCT 1080100 & 1110 AT 9/30/2019	RWIP (RETIREMENT WORK IN PROGRESS) PER BOOK ACCT 1080000 AT 9/30/2019	DIRECT ADJUSTED ACCTS 1080100 & 1110 AT 9/30/2019	TOTAL CHANGE IN ACCTS 1080100 & 1110 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
57	(392) Transportation Equipment	(4,630,793)	0	(4,630,793)	0	0	0	0	0	0	(264,370)	(4,895,163)	(441,767)
58	(393) Stores Equipment	(8,001)	0	(8,001)	0	0	0	0	0	0	0	(8,001)	(147)
59	(394) Tools, Shop & Garage	(2,641,307)	0	(2,641,307)	0	0	0	0	0	0	0	(2,641,307)	(101,673)
60	(394.1) Tools-OPC	0	0	0	(483)	0	0	0	0	0	(90,000)	(90,483)	(90,000)
61	(395) CNG Equipment	37,480	0	37,480	0	0	0	0	0	0	0	37,480	0
62	(396) Major Work Equipment	(844,448)	0	(844,448)	8,238	112	0	0	0	0	90,000	(746,098)	71,369
63	(397) Communication Equipment	(7,543,427)	0	(7,543,427)	0	0	0	0	0	0	0	(7,543,427)	(304,738)
64	(398) Miscellaneous General Plant	(80,161)	0	(80,161)	0	0	0	0	0	0	0	(80,161)	(2,173)
65	Total General Plant Reserves	($22,700,807)	($1,023,730)	($23,724,537)	$3,447,666	$72,946	$0	$0	$0	$0	($264,370)	($20,468,295)	($980,441)
66													
67	Total Accumulated Reserves For Depreciation	($178,855,613)	($1,747,687)	($180,603,300)	$1,611,206	$14,723	$0	$0	($108,789)	$0	$6,158,583	($172,927,577)	$3,167,116

Source: WKP D a 1 091_PP Rpt 1080100_1080500 Accum Dep Post TY at Sep_2019.xlsx
Source: WKP D a 1 091_PP Rpt 1110100_1110500 Accum Amort Post TY at Sep_2019.xlsx

WKP D.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK ACCTS 1080100 & 1110 AT 6/30/2019	REMOVE ASSET NOT USED BY DIVISION	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	PRO FORMA ADJUSTMENT RESERVE BALANCING 2015	PRO FORMA ADJUSTMENT RESERVE BALANCING 2019	TGS DIVISION TEST YEAR ADJUSTED ACCTS 1080100 & 1110 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES AT 9/30/2019	TGS DIVISION ADJUSTED ACCT 1060 AT 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	INTANGIBLE PLANT								
1	(301) Organization	($127,437)	$0	$127,437	$0	$0	$0	$0	$0
2	(302) Franchises & Consents	0	0	0	0	0	0	0	0
3	(303) Misc. Intangible	(278,560)	0	278,560	0	0	0	0	0
4	(303.1) Misc. Intangible	0	0	0	0	0	0	0	0
5	Total Intangible Plant Reserves	($405,997)	$0	$405,997	$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	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0
17	(367) Mains	0	0	0	0	0	0	0	0
18	(368) Compressor Station Equip	0	0	0	0	0	0	0	0
19	(369) Measure/Reg. Station Equipment	0	0	0	0	0	0	0	0
20	(371) Other Equipment	0	0	0	0	0	0	0	0
21	Total Gathering and Transmission Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0
	DISTRIBUTION PLANT								
22	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
23	(374.2) Land & Land Rights	0	0	0	0	0	0	0	0
24	(375) Structures & Improvements	0	0	0	0	0	0	0	0
25	(375.2) Other Distr Systems Struct	0	0	0	0	0	0	0	0
26	(376) Mains	0	0	0	0	0	0	0	0
27	(376.9) Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0
28	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0
29	(378) Meas. & Reg. Station - General	0	0	0	0	0	0	0	0

WKP D.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK ACCTS 1080100 & 1110 AT 6/30/2019	REMOVE ASSET NOT USED BY DIVISION	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	PRO FORMA ADJUSTMENT RESERVE BALANCING 2015	PRO FORMA ADJUSTMENT RESERVE BALANCING 2019	TGS DIVISION TEST YEAR ADJUSTED ACCTS 1080100 & 1110 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES AT 9/30/2019	TGS DIVISION ADJUSTED ACCT 1060 AT 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
30	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0
31	(380) Services	0	0	0	0	0	0	0	0
32	(381) Meters	0	0	0	0	0	0	0	0
33	(382) Meter Installations	0	0	0	0	0	0	0	0
34	(383) House Regulators	0	0	0	0	0	0	0	0
35	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0
36	(386) Other Property on Customer Premises	0	0	0	0	0	0	0	0
37	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0
38	Total Distribution Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0
	GENERAL PLANT								
39	(389) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
40	(390.1) Structures & Improvements	(6,505)	0	0	0	(5,304)	(11,809)	(514)	(12,323)
41	(390.2) Leasehold Equipment	(151,658)	35,807	0	0	0	(115,851)	8,117	(107,734)
42	(391.1) Office Furniture & Fixtures	(247,537)	0	0	15,375	(64,178)	(296,340)	19,963	(276,377)
43	(391.2) Data Processing Equipment	0	0	0	0	0	0	0	0
44	(391.3) Office Machines	0	0	0	0	0	0	0	0
45	(391.4) Audio Visual Equipment	0	0	0	0	0	0	0	0
46	(391.6) Purchased Software	0	0	0	0	0	0	0	0
47	(391.9) Computer & Equipment	1,159,644	0	0	(2,151,574)	(840,473)	(1,832,403)	(74,589)	(1,906,992)
48	(392.6) Aircraft	0	0	0	0	0	0	0	0
49	(394) Tools	(7,562)	0	0	(1,550)	442	(8,670)	(339)	(9,009)
50	(394.2) Shop Equipment	0	0	0	0	0	0	0	0
51	(397) Communication Equipment	(609,938)	0	0	(23,803)	(812)	(634,554)	(18,026)	(652,579)
52	(398) Miscellaneous General Plant	0	0	0	(269)	269	0	0	0
53	Total General Plant Reserves	$136,444	$35,807	$0	($2,161,821)	($910,057)	($2,899,627)	($65,387)	($2,965,014)
54	Total Accumulated Reserves For Depreciation	($269,553)	$35,807	$405,997	($2,161,821)	($910,057)	($2,899,627)	($65,387)	($2,965,014)
55	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%
56	Total Allocated Accumulated Reserves	($125,324)	$16,648	$188,761	($1,005,098)	($423,114)	($1,348,126)	($30,401)	($1,378,527)

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve.xlxs

WKP D.b.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - POST TEST YEAR TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK ACCTS 1080100 & 1110 AT 9/30/2019	REMOVE ASSET NOT USED BY DIVISION	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	PRO FORMA ADJUSTMENT RESERVE BALANCING 2015	PRO FORMA ADJUSTMENT RESERVE BALANCING 2019	TGS DIVISION TEST YEAR ADJUSTED ACCTS 1080100 & 1110 9/30/2019	TOTAL CHANGE IN ACCTS 1080100 & 1110 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	INTANGIBLE PLANT							
1	(301) Organization	($127,437)	$0	$127,437	$0	$0	$0	$0
2	(302) Franchises & Consents	0	0	0	0	0	0	0
3	(303) Misc. Intangible	(278,560)	0	278,560	0	0	0	0
4	(303.1) Misc. Intangible	0	0	0	0	0	0	0
5	Total Intangible Plant Reserves	($405,997)	$0	$405,997	$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	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0
17	(367) Mains	0	0	0	0	0	0	0
18	(368) Compressor Station Equip	0	0	0	0	0	0	0
19	(369) Measure/Reg. Station Equipment	0	0	0	0	0	0	0
20	(371) Other Equipment	0	0	0	0	0	0	0
21	Total Gathering and Transmission Plant Reserves	$0	$0	$0	$0	$0	$0	$0
	DISTRIBUTION PLANT							
22	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0
23	(374.2) Land & Land Rights	0	0	0	0	0	0	0
24	(375) Structures & Improvements	0	0	0	0	0	0	0
25	(375.2) Other Distr Systems Struct	0	0	0	0	0	0	0
26	(376) Mains	0	0	0	0	0	0	0
27	(376.9) Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0
28	(377) Compressor Station Equipment	0	0	0	0	0	0	0
29	(378) Meas. & Reg. Station - General	0	0	0	0	0	0	0
30	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0
31	(380) Services	0	0	0	0	0	0	0
32	(381) Meters	0	0	0	0	0	0	0
33	(382) Meter Installations	0	0	0	0	0	0	0
34	(383) House Regulators	0	0	0	0	0	0	0
35	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0
36	(386) Other Property on Customer Premises	0	0	0	0	0	0	0
37	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0
38	Total Distribution Plant Reserves	$0	$0	$0	$0	$0	$0	$0

WKP D.b.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - POST TEST YEAR TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION PER BOOK ACCTS 1080100 & 1110 AT 9/30/2019	REMOVE ASSET NOT USED BY DIVISION	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	PRO FORMA ADJUSTMENT RESERVE BALANCING 2015	PRO FORMA ADJUSTMENT RESERVE BALANCING 2019	TGS DIVISION TEST YEAR ADJUSTED ACCTS 1080100 & 1110 9/30/2019	TOTAL CHANGE IN ACCTS 1080100 & 1110 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	GENERAL PLANT							
39	(389) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0
40	(390.1) Structures & Improvements	(7,019)	0	0	0	(5,304)	(12,323)	(514)
41	(390.2) Leasehold Equipment	(151,479)	43,745	0	0	0	(107,734)	8,117
42	(391.1) Office Furniture & Fixtures	(227,574)	0	0	15,375	(64,178)	(276,377)	19,963
43	(391.2) Data Processing Equipment	0	0	0	0	0	0	0
44	(391.3) Office Machines	0	0	0	0	0	0	0
45	(391.4) Audio Visual Equipment	0	0	0	0	0	0	0
46	(391.6) Purchased Software	0	0	0	0	0	0	0
47	(391.9) Computer & Equipment	1,085,054	0	0	(2,151,574)	(840,473)	(1,906,992)	(74,589)
48	(392.6) Aircraft	0	0	0	0	0	0	0
49	(394) Tools	(7,901)	0	0	(1,550)	442	(9,009)	(339)
50	(394.2) Shop Equipment	0	0	0	0	0	0	0
51	(397) Communication Equipment	(627,964)	0	0	(23,803)	(812)	(652,579)	(18,026)
52	(398) Miscellaneous General Plant	0	0	0	(269)	269	0	0
53	Total General Plant Reserves	$63,119	$43,745	$0	($2,161,821)	($910,057)	($2,965,014)	($65,387)
54	Total Accumulated Reserves For Depreciation	($342,878)	$43,745	$405,997	($2,161,821)	($910,057)	($2,965,014)	($65,387)
55	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%
56	Total Allocated Accumulated Reserves	($159,415)	$20,338	$188,761	($1,005,098)	($423,114)	($1,378,527)	($30,401)

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve.xlsx

WKP D.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK ACCTS 1080100 & 1110 AT 6/30/2019	REMOVE ARTWORK	REMOVE AVIATION	REMOVE ONE GAS FOUNDATION SOFTWARE	CORPORATE TEST YEAR ADJUSTED ACCTS 1080100 & 1110 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES AT 9/30/2019	CORPORATE ADJUSTED ACCTS 1080100 & 1110 AT 9/30/2019	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	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		
4	Total Intangible Plant Reserves	$0	$0	$0	$0	$0	$0	$0		
	GATHERING AND TRANSMISSION PLANT									
5	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0		
6	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0		
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0		
8	(329) Other Structures	0	0	0	0	0	0	0		
9	(332) Field Lines	0	0	0	0	0	0	0		
10	(333) Field Compressor Station Equip	0	0	0	0	0	0	0		
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0		
12	(336) Purification Equipment	0	0	0	0	0	0	0		
13	(337) Other Equip	0	0	0	0	0	0	0		
14	(365) Land & Land Rights	0	0	0	0	0	0	0		
15	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0		
16	(367) Mains	0	0	0	0	0	0	0		
17	(368) Compressor Station Equip	0	0	0	0	0	0	0		
18	(369) Measure/Reg. Station Equipment	0	0	0	0	0	0	0		
19	(371) Other Equipment	0	0	0	0	0	0	0		
20	Total Gathering and Transmission Plant Reserves	$0	$0	$0	$0	$0	$0	$0		
	DISTRIBUTION PLANT									
21	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0		
22	(374.2) Land & Land Rights	0	0	0	0	0	0	0		
23	(375) Structures & Improvements	0	0	0	0	0	0	0		
24	(375.2) Other Distr Systems Struct	0	0	0	0	0	0	0		
25	(376) Mains	0	0	0	0	0	0	0		
26	(376.9) Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0		
27	(377) Compressor Station Equipment	0	0	0	0	0	0	0		
28	(378) Meas. & Reg. Station - General	0	0	0	0	0	0	0		
29	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0		
30	(380) Services	0	0	0	0	0	0	0		
31	(381) Meters	0	0	0	0	0	0	0		
32	(382) Meter Installations	0	0	0	0	0	0	0		
33	(383) House Regulators	0	0	0	0	0	0	0		
34	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0		
35	(386) Other Property on Customer Premises	0	0	0	0	0	0	0		
36	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0		
37	Total Distribution Plant Reserves	$0	$0	$0	$0	$0	$0	$0		

WKP D.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK ACCTS 1080100 & 1110 AT 6/30/2019	REMOVE ARTWORK	REMOVE AVIATION	REMOVE ONE GAS FOUNDATION SOFTWARE	CORPORATE TEST YEAR ADJUSTED ACCTS 1080100 & 1110 AT 6/30/2019	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES AT 9/30/2019	CORPORATE ADJUSTED ACCTS 1080100 & 1110 AT 9/30/2019	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	GENERAL PLANT									
38	(389) Land & Land Rights	$0	$0	$0	$0	0	0	0	25.01%	$0
39	(390.1) Structures & Improvements	(1,069)	0	0	0	(1,069)	(347)	(1,416)	25.01%	(354)
40	(390.2) Leasehold Improvements	(1,981,071)	0	0	0	(1,981,071)	(152,538)	(2,133,609)	25.01%	(533,616)
41	(391.1) Office Furniture & Equipment	(798,651)	0	0	0	(798,651)	(60,102)	(858,753)	25.01%	(214,774)
42	(391.19) Airplane Hanger Furniture	(3,190)	0	3,190	0	0	0	0	25.01%	0
43	(391.2) Data Processing Equipment	0	0	0	0	0	0	0	25.01%	0
44	(391.3) Office Machines	(13,874)	0	0	0	(13,874)	(453)	(14,327)	25.01%	(3,583)
45	(391.4) Audio Visual Equipment	(1,020,023)	0	0	0	(1,020,023)	(70,115)	(1,090,138)	25.01%	(272,643)
46	(391.5) Artwork	(10,018)	10,018	0	0	0	0	0	25.01%	0
47	(391.6) Purchased Software	(25,970,022)	0	0	56,099	(25,913,923)	(1,672,013)	(27,585,936)	25.01%	(6,899,242)
48	(391.6) Banner Software	(10,832,948)	0	0	0	(10,832,948)	9,540,467	(1,292,482)	30.41%	(393,045)
49	(391.6) PowerPlant System	(344,883)	0	0	0	(344,883)	(16,726)	(361,608)	24.02%	(86,840)
50	(391.6) Riskworks	0	0	0	0	0	0	0	0.00%	0
51	(391.6) Maximo	(2,193,194)	0	0	0	(2,193,194)	(59,935)	(2,253,129)	24.71%	(556,717)
52	(391.6) Dynamic Risk Assessment	0	0	0	0	0	0	0	0.00%	0
53	(391.6) Concur Project	(47,648)	0	0	0	(47,648)	0	(47,648)	27.95%	(13,318)
54	(391.6) Journey-Employee-ODC Distrigas	(24,935,117)	0	0	0	(24,935,117)	(1,337,694)	(26,272,810)	25.01%	(6,570,830)
55	(391.6) Journey-Employee Count	(798,078)	0	0	0	(798,078)	($35,544)	(833,622)	27.95%	(233,006)
56	(391.6) Ariba Software	0	0	0	0	0	$0	0	30.96%	0
57	(391.6) Accounts Payable Software	(124,167)	0	0	0	(124,167)	($17,366)	(141,534)	30.96%	(43,813)
58	(391.8) Micro Computer Software	(3,636,858)	0	0	0	(3,636,858)	($829,838)	(4,466,696)	25.01%	(1,117,121)
59	(391.81) Aircraft Computer Equipment	(75,515)	0	75,515	0	0	$0	0	25.01%	0
60	(391.9) Computer & Equipment	0	0	0	0	0	$0	0	25.01%	0
61	(392.6) Aircraft	(7,631,532)	0	7,631,532	0	0	$0	0	25.01%	0
62	(394) Tools	0	0	0	0	0	$0	0	25.01%	0
63	(394.1) Tools	0	0	0	0	0	$0	0	25.01%	0
64	(394.2) Shop Equipment	0	0	0	0	0	$0	0	25.01%	0
65	(396) Major Work Equipment	0	0	0	0	0	$0	0	25.01%	0
66	(397) Communication Equipment	(9,381)	0	0	0	(9,381)	($1,281)	(10,663)	25.01%	(2,667)
67	(397.2) Telephone Equipment	0	0	0	0	0	$0	0	25.01%	0
68	(398) Miscellaneous General Plant	0	0	0	0	0	$0	0	25.01%	0
69	Total General Plant Reserves	($80,427,238)	$10,018	$7,710,237	$56,099	($72,650,884)	$5,286,515	($67,364,369)	25.15%	($16,941,570)
70	Total Accumulated Reserves For Depreciation	($80,427,238)	$10,018	$7,710,237	$56,099	($72,650,884)	$5,286,515	($67,364,369)		
71	Allocation Factor to TGS	25.1492%	25.1492%	25.1492%	25.1492%	25.1492%	25.1492%	25.1492%		
72	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%		
73	Total Allocated Accumulated Reserves	($9,404,053)	$1,171	$901,529	$6,559	($8,494,793)	$618,132	($7,876,661)		

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve.xlxs

WKP D.c.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - POST TEST YEAR CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK ACCTS 1080100 & 1110 AT 9/30/2019	REMOVE ARTWORK	REMOVE AVIATION	REMOVE ONE GAS FOUNDATION SOFTWARE	CORPORATE ADJUSTED ACCT 1080100 & 1110 AT 9/30/2019	TOTAL CHANGE IN ACCT 1080100 & 1110 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)
	INTANGIBLE PLANT						
1	(301) Organization	$0	$0	$0	$0	$0	$0
2	(302) Franchises & Consents	0	0	0	0	0	0
3	(303) Misc. Intangible	0	0	0	0	0	0
4	(303.1) Misc. Intangible	0	0	0	0	0	0
4	Total Intangible Plant Reserves	$0	$0	$0	$0	$0	$0
	GATHERING AND TRANSMISSION PLANT						
5	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0
8	(329) Other Structures	0	0	0	0	0	0
9	(332) Field Lines	0	0	0	0	0	0
10	(333) Field Compressor Station Equip	0	0	0	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0
12	(336) Purification Equipment	0	0	0	0	0	0
13	(337) Other Equip	0	0	0	0	0	0
14	(365) Land & Land Rights	0	0	0	0	0	0
15	(366) Meas/Reg Station Structures	0	0	0	0	0	0
16	(367) Mains	0	0	0	0	0	0
17	(368) Compressor Station Equip	0	0	0	0	0	0
18	(369) Measure/Reg. Station Equipment	0	0	0	0	0	0
19	(371) Other Equipment	0	0	0	0	0	0
20	Total Gathering and Transmission Plant Reserves	$0	$0	$0	$0	$0	$0
	DISTRIBUTION PLANT						
21	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0
22	(374.2) Land & Land Rights	0	0	0	0	0	0
23	(375) Structures & Improvements	0	0	0	0	0	0
24	(375.2) Other Distr Systems Struct	0	0	0	0	0	0
25	(376) Mains	0	0	0	0	0	0
26	(376.9) Mains - Cathodic Protection Anodes	0	0	0	0	0	0
27	(377) Compressor Station Equipment	0	0	0	0	0	0
28	(378) Meas. & Reg. Station - General	0	0	0	0	0	0
29	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0	0

WKP D.c.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - POST TEST YEAR CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK ACCTS 1080100 & 1110 AT 9/30/2019	REMOVE ARTWORK	REMOVE AVIATION	REMOVE ONE GAS FOUNDATION SOFTWARE	CORPORATE ADJUSTED ACCT 1080100 & 1110 AT 9/30/2019	TOTAL CHANGE IN ACCT 1080100 & 1110 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)
30	(380) Services	0	0	0	0	0	0
31	(381) Meters	0	0	0	0	0	0
32	(382) Meter Installations	0	0	0	0	0	0
33	(383) House Regulators	0	0	0	0	0	0
34	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0
35	(386) Other Property on Customer Premises	0	0	0	0	0	0
36	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0
37	Total Distribution Plant Reserves	$0	$0	$0	$0	$0	$0
	GENERAL PLANT						
38	(389) Land & Land Rights	$0	$0	$0	$0	0	$0
39	(390.1) Structures & Improvements	(1,416)	0	0	0	(1,416)	(347)
40	(390.2) Leasehold Improvements	(2,133,609)	0	0	0	(2,133,609)	(152,538)
41	(391.1) Office Furniture & Equipment	(858,753)	0	0	0	(858,753)	(60,102)
42	(391.19) Airplane Hanger Furniture	(3,388)	0	3,388	0	0	0
43	(391.2) Data Processing Equipment	0	0	0	0	0	0
44	(391.3) Office Machines	(14,327)	0	0	0	(14,327)	(453)
45	(391.4) Audio Visual Equipment	(1,090,138)	0	0	0	(1,090,138)	(70,115)
46	(391.5) Artwork	(10,635)	10,635	0	0	0	0
47	(391.6) Purchased Software	(27,642,555)	0	0	56,619	(27,585,936)	(1,672,013)
48	(391.6) Banner Software	(1,292,482)	0	0	0	(1,292,482)	9,540,467
49	(391.6) PowerPlant System	(361,608)	0	0	0	(361,608)	(16,726)
50	(391.6) Riskworks	0	0	0	0	0	0
51	(391.6) Maximo	(2,253,129)	0	0	0	(2,253,129)	(59,935)
52	(391.6) Dynamic Risk Assessment	0	0	0	0	0	0
53	(391.6) Concur Project	(47,648)	0	0	0	(47,648)	0
54	(391.6) Journey-Employee-ODC Distrigas	(26,272,810)	0	0	0	(26,272,810)	(1,337,694)
55	(391.6) Journey-Employee Count	(833,622)	0	0	0	(833,622)	(35,544)
56	(391.6) Ariba Software	0	0	0	0	0	0
57	(391.6) Accounts Payable Software	(141,534)	0	0	0	(141,534)	(17,366)
58	(391.8) Micro Computer Software	(4,466,696)	0	0	0	(4,466,696)	(829,838)
59	(391.81) Aircraft Computer Equipment	(82,058)	0	82,058	0	0	0
60	(391.9) Computer & Equipment	0	0	0	0	0	0
61	(392.6) Aircraft	(7,845,189)	0	7,845,189	0	0	0
62	(394) Tools	0	0	0	0	0	0

WKP D.c.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - POST TEST YEAR CORPORATE

LINE NO.	DESCRIPTION	CORPORATE PER BOOK ACCTS 1080100 & 1110 AT 9/30/2019	REMOVE ARTWORK	REMOVE AVIATION	REMOVE ONE GAS FOUNDATION SOFTWARE	CORPORATE ADJUSTED ACCT 1080100 & 1110 AT 9/30/2019	TOTAL CHANGE IN ACCT 1080100 & 1110 FROM 6/30/2019 TO 9/30/2019
		(a)	(b)	(c)	(d)	(e)	(f)
63	(394.1) Tools	0	0	0	0	0	0
64	(394.2) Shop Equipment	0	0	0	0	0	0
65	(396) Major Work Equipment	0	0	0	0	0	0
66	(397) Communication Equipment	(10,663)	0	0	0	(10,663)	(1,281)
67	(397.2) Telephone Equipment	0	0	0	0	0	0
68	(398) Miscellaneous General Plant	0	0	0	0	0	0
69	Total General Plant Reserves	($75,362,258)	$10,635	$7,930,635	$56,619	($67,364,369)	$5,286,515
70	Total Accumulated Reserves For Depreciation	($75,362,258)	$10,635	$7,930,635	$56,619	($67,364,369)	$5,286,515
71	Allocation Factor to TGS	25.1492%	25.1492%	25.1492%	25.1492%	25.1492%	25.1492%
72	Allocation Factor to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%
73	Total Allocated Accumulated Reserves	($8,811,824)	$1,244	$927,299	$6,620	($7,876,661)	$618,132

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve.xlxs

SCHEDULE E

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COST OF CAPITAL

LINE NO.	DESCRIPTION	RATIO	COST RATE %	COMPOSITE RATE %
		(a)	(b)	(c)
1	Long-Term Debt	37.88%	4.53%	1.71%
2	Common Equity	62.12%	10.00%	6.21%
3	Total	100.000%		7.93%

Source: SCH E Cost of Capital_CGSA.xlsx

SCHEDULE F

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

FEDERAL INCOME TAX

LINE NO.	DESCRIPTION	REFERENCE	PER BOOKS	ADJUSTMENT	TEST YEAR ADJUSTED
			(a)	(b)	(c)
1	Rate Base	B	$444,578,089	$28,889,947	$473,468,036
2	Rate of Return	E	7.9266%	7.9266%	7.9266%
3	Required Return		$35,239,713	$2,289,977	$37,529,690
4	Less: Interest on Long-Term Debt (1)		7,623,308	495,384	8,118,693
5	Net After Tax Income before parking adjustment		$27,616,405	$1,794,592	$29,410,997
6	Add: Parking Expense - no longer tax		140,742		140,742
7	Net After Tax Income		$27,757,147	$1,794,592	$29,551,739
8	Gross-Up Factor [1 / (1-0.21)]		1.2658228	1.2658228	1.2658228
9	Net Taxable Income		$35,135,629	$2,271,636	$37,407,265
10	Tax Rate		21.0000%	21.0000%	21.0000%
11	Federal Income Tax		$7,378,482	$477,044	$7,855,526
12	Net Income Tax Expense		$7,378,482	$477,044	$7,855,526

	Note (1)				
13	Debt Component of Return	E	1.7147%		1.7147%
14	Total Rate Base	B	$444,578,089		$473,468,036
15	Interest on Long-Term Debt		$7,623,308		$8,118,693

Note (2)

17 Per IRS Notice 2018-99, the Tax Cuts and Jobs Act of 2017 added Code Section 274(a)(4) precluding employers form deducting for tax purposes the amount paid to a third party for the use of a parking lot.

Source: SCH F TGS Parking Expense_CGSA.xlsx

SCHEDULE G
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$178,503,125	($69,498,918)	$109,004,207
	OPERATING EXPENSES				
2	Cost of Gas	G-1	$75,042,680	($75,042,680)	$0
3	Base Payroll Expense	G-4	18,221,598	1,777,410	19,999,008
4	Overtime Payroll Expense	G-5	1,331,152	80,976	1,412,127
5	Employee Benefits and Payroll Taxes	G-6	7,713,156	766,309	8,479,465
6	Pension and Other Post Employment Benefits Regulatory Asset Amortization	G-7	289,452	(5,306)	284,147
7	Incentive Compensation	G-8	4,511,994	(505,515)	4,006,479
8	Miscellaneous Adjustments	G-9	2,774,342	(2,774,342)	0
9	Rents and Leases Adjustment	G-10	1,451,795	(79,333)	1,372,463
10	Interest on Customer Deposits	G-11	117,153	33,639	150,792
11	Uncollectible Expense	G-12	527,099	58,580	585,680
12	Injuries and Damages	G-13	346,222	(124,868)	221,354
13	Advertising Expense	G-14	37,109	0	37,109
14	Depreciation and Amortization Expense	G-15	18,803,351	2,547,785	21,351,137
15	Ad Valorem Tax Expense	G-16	4,083,352	301,851	4,385,203
16	Texas Franchise Tax Expense	G-17	0	813,039	813,039
17	Stores Load Clearing	G-18	107,266	15,588	122,854
18	Transportation & Work Equipment Clearing	G-19	1,525,518	328,562	1,854,079
19	Regulatory Expense	G-20	46,699	(27,241)	19,458
20	Distrigas % Adjustment	G-21	0	140,112	140,112
21	Conservation Program Reimbursement-Not Used	G-23	0	0	0
22	Pipeline Integrity Testing	G-24	0	276,480	276,480
23	Hurricane Harvey Expenses	G-25	0	119,065	119,065
24	Unadjusted Expenses		14,816,166	0	14,816,166
25	Total Operating Expense Adjustments		$151,746,106	($71,299,890)	$80,446,216
26	Net Operating Revenue & Expense Adjustments		$26,757,019	$1,800,972	$28,557,991

Schedule G
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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		$166,636,721	($69,724,326)	$96,912,395
2	Forfeited Discounts	4870		0	0	0
3	Misc Fees	4880		2,137,994	277,029	2,415,023
4	Transportation	4893		9,318,914	357,875	9,676,789
5	Misc. Rent Revenue	4930		0	0	0
6	Other Utility Revenue	4950		409,496	(409,496)	0
7	Total Revenue			$178,503,125	($69,498,918)	$109,004,207
8	COST OF GAS	805		$75,042,680	($75,042,680)	$0
	DEPRECIATION & AMORTIZATION					
9	Depreciation and Amortization Expense	4030-4050		$18,803,351	$2,547,785	$21,351,137
10	Pension and OPEB Reg Asset Amortization Expense	4073		336,152	(5,306)	330,846
11	Total Depr. & Amort.			$19,139,503	$2,542,480	$21,681,983
	TAXES OTHER THAN INCOME					
12	Payroll	4081		$1,213,765	$85,956	$1,299,721
13	Ad Valorem	4081	190	4,083,352	301,851	4,385,203
14	Revenue Related	4081	133, 138 & 140	13,277	0	13,277
15	Other	4081	233	511,780	813,039	1,324,819
16	Total Taxes Other Than Income			$5,822,174	$1,200,847	$7,023,021
17	INTEREST ON CUSTOMER DEPOSITS	4310		$117,153	$33,639	$150,792
	TRANSMISSION AND HIGH PRESSURE DISTRIBUTION					
18	Underground Storage	8140-8360		$200	$0	$200
19	Operation Supervision and Engineering	8500		3,194	0	3,194
20	Transmission Communication Equip	8520		0	0	0
21	Compressor Station Labor and Expenses	8530		17,669	149	17,819
22	Mains Expenses	8560		614,920	297,795	912,715
23	Mains Expenses - OPC	8560		9,584	0	9,584
24	Measuring and Regulating Station Expenses	8570		1,547	24	1,571
25	Trans/Compression of Gas by Others	8580		0	0	0
26	Other Expenses	8590		5,116	(4)	5,112
27	Rent	8600		2,919	0	2,919
28	Maintenance Supervison and Engineering	8610		6,860	0	6,860
29	Maintenance of Mains	8630		6,458	128	6,586
30	Maintenance of Mains - OPC	8630		147	0	147
31	Maintenance of Measuring and Regulating Station Equipme	8650		5,340	106	5,446
32	Maintenance of Communication Equipment	8660		0	0	0
33	Total Transmission			$673,955	$298,199	$972,153
	DISTRIBUTION OPERATIONS					
34	Supervision and Engineering	8700		$691,042	$44,777	$735,819
35	Distribution Load Dispatch	8710		226,304	33,895	260,199
36	Mains & Services	8740		3,878,987	202,526	4,081,513
37	Mains & Services - OPC	8740		164,077	0	164,077
38	Meas. Stat. Exp. - General	8750		425,328	17,594	442,921
39	Meas & Reg. Stat. Exp. - General - OPC	8750		6,750	0	6,750
40	Meter & House Reg. Exp. - Ind.	8760		60,619	7,041	67,660
41	Meas & Reg. Stat. Exp. - Ind. - OPC	8760		413	0	413
42	Meter & House Reg. Exp.-City Gate	8770		3,306	485	3,791
43	Meas & Reg. Stat. Exp. - City Gate - OPC	8770		468	0	468
44	Meter & House Reg. Exp.	8780		4,068,431	278,738	4,347,169
45	Meter & House Reg. Exp. - OPC	8780		4	0	4
46	Customer Installation Exp	8790		76,139	8,196	84,335
47	Other Expense	8800		1,213,073	232,921	1,445,994
48	Other Expense - OPC	8800		132	0	132
49	Rents	8810		(188,295)	0	(188,295)
50	Corporate & Div. Exp.	8820		0	0	0
51	Total Distribution Operations			$10,626,778	$826,172	$11,452,950

Schedule G
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

SUMMARY OF OPERATING REVENUES & EXPENSES

LINE NO.	DESCRIPTION	ACCOUNT NUMBER	SUB ACCOUNT	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
				(a)	(b)	(c)
	DISTRIBUTION MAINTENANCE					
52	Supervision and Engineering	8850		$72	$0	$72
53	Struct. & Improv.	8860		362,515	0	362,515
54	Mains	8870		3,036,329	176,836	3,213,164
55	Mains - OPC	8870		100,539	0	100,539
56	Meas. & Reg. Stat. Exp. - Gen	8890		387,629	25,222	412,851
57	Meas. & Reg. Stat. Exp. - Gen - OPC	8890		979	0	979
58	Meas. & Reg. Stat. Exp. - Ind.	8900		542,345	43,160	585,505
59	Meas. & Reg. Stat. Exp. - City Gate	8910		18,486	1,337	19,823
60	Maintenance of Services	8920		693,669	47,256	740,925
61	Meters & House Reg.	8930		6,695	397	7,092
62	Other Equipment	8940		0	0	0
63	Clearing - Meter Shop - Small Meters	8950		0	0	0
64	Clearing - Meter Shop - Large Meters	8960		0	0	0
65	Total Distribution Maintenance			$5,149,258	$294,207	$5,443,464
66	Total Distribution Expense			$15,776,036	$1,120,379	$16,896,414
	CUSTOMER ACCOUNTING					
67	Supervision	9010		$137,799	$16,700	$154,499
68	Meter Reading	9020		1,306,746	44,446	1,351,191
69	Customer Accounting	9030		3,833,650	282,316	4,115,966
70	Bad Debts	9040		527,099	58,580	585,680
71	Miscellaneous	9050		341,460	1,011	342,471
72	Total Customer Accounting			$6,146,754	$403,053	$6,549,807
	CUSTOMER INFORMATION					
73	Supervision	9070		$0	$0	$0
74	Customer Assistance Expense	9080		698,000	45,891	743,891
75	Inform. & Instruct. Adver. Exp.	9090		93,401	(104)	93,297
76	Customer Service & Informational Svc.	9100		0	0	0
77	Total Customer Information			$791,401	$45,787	$837,188
	SALES					
78	Supervision	9110		$0	$0	$0
79	Demonstrating and Selling Expense	9120		0	0	0
80	Advertising	9130		23,611	0	23,611
81	Employee Sales Referrals	9140		0	0	0
82	Misc. Gas Sales Expense	9163		0	0	0
83	Total Sales			$23,611	$0	$23,611
84	Total Customer Accounts Expense			$6,961,766	$448,840	$7,410,606
	ADMINISTRATIVE & GENERAL					
85	Salaries	9200		$6,277,907	$432,367	$6,710,274
86	Office Supplies & Expenses	9210		1,538,483	5,420	1,543,903
87	Office Supplies & Expenses - OPC	9210		54	0	54
88	Transferred Credit	9220		(4,102,030)	0	(4,102,030)
89	Outside Services	9230		265,074	(4,248)	260,826
90	Property Insurance	9240		187,108	26,737	213,845
91	Injuries & Damages	9250		1,168,245	86,515	1,254,759
92	Employee Pensions & Benefits	9260		5,120,758	115,261	5,236,020
93	Regulatory Commission Expense	9280		228,922	(27,176)	201,746
94	Duplicate Charges- Credit	9290		0	0	0
95	General Advertising Expense	9301		10,076	0	10,076
96	Misc. General Expenses	9302		15,828,151	(2,462,646)	13,365,505
97	Rents	9310		1,451,795	(73,824)	1,377,972
98	Maintenance of General Plant	9320		238,296	0	238,296
99	Misc. General Expenses	9400's		0	0	0
100	Total Administrative & General Expense			28,212,839	(1,901,593)	26,311,246
101	Total Operating Expense			$151,746,106	($71,299,890)	$80,446,216
102	Earnings Before Income Tax & Interest Expense			$26,757,019	$1,800,972	$28,557,991

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

OPERATING REVENUE & EXPENSE ADJUSTMENTS

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	PER BOOKS WKP G.a.2	Notes	REMOVE COST OF GAS RELATED ADJ G-1	NORMALIZE GAS SALES REVENUE ADJ G-2	NORMALIZE OTHER UTILITY SALES REVENUE ADJ G-3	BASE PAYROLL ADJ G-4	OVERTIME PAYROLL ADJ G-5	BENEFITS & PAYROLL TAX ADJ G-6	PENSION & OPEB REGULATORY ASSET AMORTIZATION ADJ G-7	INCENTIVE COMPENSATION ADJ G-8	MISC. ADJ G-9	RENT ADJ G-10	CUSTOMER DEPOSITS ADJ G-11	UNCOLLECTIBLE EXPENSE ADJ G-12
				(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Revenue																
1	Gas Sales Revenue	480-482		$166,636,721		($75,042,680)	$5,318,354	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Forfeited Discounts	4870		0		0	0	0	0	0	0	0	0	0	0	0	0
3	Misc Fees	4880		2,137,994		0	0	277,029	0	0	0	0	0	0	0	0	0
4	Transportation	4893		9,318,914		0	0	357,875	0	0	0	0	0	0	0	0	0
5	Misc. Rent Revenue	4930		0		0	0	0	0	0	0	0	0	0	0	0	0
6	Other Utility Revenue	4950		409,496		0	0	(409,496)	0	0	0	0	0	0	0	0	0
7	Total Revenue			$178,503,125		($75,042,680)	$5,318,354	$225,408	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Cost of Gas	805		$75,042,680		($75,042,680)											
	Deprec. & Amort. Expense																
9	Depreciation and Amortization Expense	4030-4050		$18,803,351		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	Pension and OPEB Reg Asset Amortization Expense	4073		336,152	2	0	0	0	0	0	0	(5,306)	0	0	0	0	0
11	Total Depr. & Amort.			$19,139,503		$0	$0	$0	$0	$0	$0	($5,306)	$0	$0	$0	$0	$0
	Taxes Other Than Income																
12	Payroll	4081		$1,213,765		$0	$0	$0	$0	$0	$59,201	$0	($3,594)	$30,350	$0	$0	$0
13	Ad Valorem	4081	190	4,083,352		0	0	0	0	0	0	0	0	0	0	0	0
14	Revenue Related	4081	133, 138 & 140	13,277		0	0	0	0	0	0	0	0	0	0	0	0
15	Other	4081	131, 233 & 995	511,780		0	0	0	0	0	0	0	0	0	0	0	0
16	Total Taxes Other Than Income			$5,822,174		$0	$0	$0	$0	$0	$59,201	$0	($3,594)	$30,350	$0	$0	$0
17	Interest on Customer Deposits	4310		$117,153		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$33,639	$0
18	Storage Misc.	8140-8360		$200		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Transmission & High Pressure Distribution																
19	Operation Supervision and Engineering	8500		$3,194		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	Transmission Communication Equip	8520		0		0	0	0	0	0	0	0	0	0	0	0	0
21	Compressor Station Labor and Expenses	8530		17,669		0	0	0	149	1	0	0	0	0	0	0	0
22	Mains Expenses	8560		614,920		0	0	0	13,254	1,241	0	0	0	(4)	0	0	0
23	Mains Expenses - OPC	8560		9,584		0	0	0	0	0	0	0	0	0	0	0	0
24	Measuring and Regulating Station Expenses	8570		1,547		0	0	0	24	0	0	0	0	0	0	0	0
25	Trans/Compression of Gas by Others	8580		0		0	0	0	0	0	0	0	0	0	0	0	0
26	Other Expenses	8590		5,116		0	0	0	0	0	0	0	0	(4)	0	0	0
27	Rent	8600		2,919		0	0	0	0	0	0	0	0	0	0	0	0
28	Maintenance Supervison and Engineering	8610		6,860		0	0	0	0	0	0	0	0	0	0	0	0
29	Maintenance of Mains	8630		6,458		0	0	0	121	2	0	0	0	0	0	0	0
30	Maintenance of Mains - OPC	8630		147		0	0	0	0	0	0	0	0	0	0	0	0
31	Maintenance of Measuring and Regulating Station Equipment	8650		5,340		0	0	0	105	1	0	0	0	0	0	0	0
32	Maintenance of Communication Equipment	8660		0		0	0	0	0	0	0	0	0	0	0	0	0
33	Total Transmission			$673,755		$0	$0	$0	$13,653	$1,246	$0	$0	$0	($8)	$0	$0	$0
	Distribution Operations																
34	Supervision and Engineering	8700		$691,042		$0	$0	$0	$40,274	$2,343	$0	$0	$0	($897)	$0	$0	$0
35	Distribution Load Dispatch	8710		226,304		0	0	0	34,107	200	0	0	0	(412)	0	0	0
36	Mains & Services	8740		3,878,987		0	0	0	41,495	6,815	0	0	0	(126)	0	0	0
37	Mains & Services - OPC	8740		164,077		0	0	0	0	0	0	0	0	0	0	0	0
38	Meas & Reg. Stat. Exp. - General	8750		425,328		0	0	0	13,206	1,446	0	0	0	(1,730)	0	0	0
39	Meas & Reg. Stat. Exp. - General - OPC	8750		6,750		0	0	0	0	0	0	0	0	0	0	0	0

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TWELVE MONTHS ENDED JUNE 30, 2019
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OPERATING REVENUE & EXPENSE ADJUSTMENTS

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	PER BOOKS WKP G.a.2	Notes	REMOVE COST OF GAS RELATED ADJ G-1	NORMALIZE GAS SALES REVENUE ADJ G-2	NORMALIZE OTHER UTILITY SALES REVENUE ADJ G-3	BASE PAYROLL ADJ G-4	OVERTIME PAYROLL ADJ G-5	BENEFITS & PAYROLL TAX ADJ G-6	PENSION & OPEB REGULATORY ASSET AMORTIZATION ADJ G-7	INCENTIVE COMPENSATION ADJ G-8	MISC. ADJ G-9	RENT ADJ G-10	CUSTOMER DEPOSITS ADJ G-11	UNCOLLECTIBLE EXPENSE ADJ G-12
				(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
40	Meas & Reg. Stat. Exp. - Ind.	8760		60,619		0	0	0	6,420	208	0	0	0	0	0	0	0
41	Meas & Reg. Stat. Exp. - Ind. - OPC	8760		413		0	0	0	0	0	0	0	0	0	0	0	0
42	Meas & Reg. Stat. Exp. - City Gate	8770		3,306		0	0	0	464	3	0	0	0	0	0	0	0
43	Meas & Reg. Stat. Exp. - City Gate - OPC	8770		468		0	0	0	0	0	0	0	0	0	0	0	0
44	Meter & House Reg. Exp.	8780		4,068,431		0	0	0	136,807	23,479	0	0	0	(5)	0	0	0
45	Meter & House Reg. Exp. - OPC	8780		4		0	0	0	0	0	0	0	0	0	0	0	0
46	Customer Installation Exp	8790		76,139		0	0	0	3,963	680	0	0	0	0	0	0	0
47	Other Expense	8800		1,213,073		0	0	0	32,051	3,877	0	0	0	179,152	0	0	0
48	Other Expense - OPC	8800		132		0	0	0	0	0	0	0	0	0	0	0	0
49	Rents	8810		(188,295)		0	0	0	0	0	0	0	0	0	0	0	0
50	Corporate & TGS Division Expenses Credit	8820		0		0	0	0	0	0	0	0	0	0	0	0	0
51	Total Distribution Operations			$10,626,778		$0	$0	$0	$308,785	$39,050	$0	$0	$0	$175,981	$0	$0	$0
	Distribution Maintenance											0	0	175,981			
52	Supervision and Engineering	8850		$72		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
53	Struct. & Improv.	8860		362,515		0	0	0	0	0	0	0	0	0	0	0	0
54	Mains	8870		3,036,329		0	0	0	86,298	13,116	0	0	0	(1)	0	0	0
55	Mains - OPC	8870		100,539		0	0	0	0	0	0	0	0	0	0	0	0
56	Meas. & Reg. Stat. Exp. - Gen	8890		387,629		0	0	0	12,918	2,135	0	0	0	0	0	0	0
57	Meas. & Reg. Stat. Exp. - Gen - OPC	8890		979		0	0	0	0	0	0	0	0	0	0	0	0
58	Meas. & Reg. Stat. Exp. - Ind.	8900		542,345		0	0	0	22,577	3,314	0	0	0	(45)	0	0	0
59	Meas. & Reg. Stat. Exp. - City Gate	8910		18,486		0	0	0	755	128	0	0	0	0	0	0	0
60	Maintenance of Services	8920		693,669		0	0	0	20,609	3,537	0	0	0	0	0	0	0
61	Meters & House Reg.	8930		6,695		0	0	0	299	51	0	0	0	0	0	0	0
62	Other Equipment	8940		0		0	0	0	0	0	0	0	0	0	0	0	0
63	Clearing - Meter Shop - Small Meters	8950		0		0	0	0	0	0	0	0	0	0	0	0	0
64	Clearing - Meter Shop - Large Meters	8960		0		0	0	0	0	0	0	0	0	0	0	0	0
65	Total Distribution Maintenance			$5,149,258		$0	$0	$0	$143,455	$22,281	$0	$0	$0	($46)	$0	$0	$0
66	Total Distribution			$15,776,036		$0	$0	$0	$452,241	$61,331	$0	$0	$0	$175,936	$0	$0	$0
	Customer Accounting																
67	Supervision	9010		$137,799		$0	$0	$0	$17,590	$103	$0	$0	$0	($993)	$0	$0	$0
68	Meter Reading	9020		1,306,746		0	0	0	22,134	3,799	0	0	0	0	0	0	0
69	Customer Accounting	9030		3,833,650		0	0	0	275,132	2,773	0	0	0	(1,806)	0	0	0
70	Bad Debts	9040		527,099		0	0	0	0	0	0	0	0	0	0	0	58,580
71	Miscellaneous	9050		341,460		0	0	0	579	99	0	0	0	(6)	0	0	0
72	Total Customer Accounting			$6,146,754		$0	$0	$0	$315,434	$6,774	$0	$0	$0	($2,805)	$0	$0	$58,580
	Customer Information																
73	Supervision	9070		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
74	Customer Assistance Expense	9080		698,000		0	0	0	42,602	3,765	0	0	0	(476)	0	0	0
75	Inform. & Instruct. Adver. Exp.	9090		93,401		0	0	0	0	0	0	0	0	(104)	0	0	0
76	Customer Svc and Informational Svc	9100		0		0	0	0	0	0	0	0	0	0	0	0	0
77	Total Customer Information			$791,401		$0	$0	$0	$42,602	$3,765	$0	$0	$0	($580)	$0	$0	$0
	Sales																
78	Supervision	9110		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
79	Demonstrating and Selling Expense	9120		$0					0	0	0	0	0	0	0	0	0
80	Advertising	9130		23,611		0	0	0	0	0	0	0	0	0	0	0	0
81	Employee Sales Referrals	9140		0		0	0	0	0	0	0	0	0	0	0	0	0
82	Misc. Gas Sales Expense	9163		0		0	0	0	0	0	0	0	0	0	0	0	0
83	Total Sales			$23,611		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

OPERATING REVENUE & EXPENSE ADJUSTMENTS

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	PER BOOKS WKP G.a.2 (a)	Notes	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)
84	Total Customer Accounts Expense			$6,961,766		$0	$0	$0	$358,036	$10,539	$0	$0	$0	($3,385)	$0	$0	$58,580
	Administrative & General																
85	Salaries	9200		$6,277,907		$0	$0	$0	$427,687	$4,680	$0	$0	$0	$0	$0	$0	$0
86	Office Supplies & Expenses	9210		1,538,483		0	0	0	0	0	0	0	0	4,975	0	0	0
	Office Supplies & Expenses - OPC	9210		54		0	0	0	0	0	0	0	0	0	0	0	0
87	Transferred Credit	9220		(4,102,030)		0	0	0	0	0	0	0	0	0	0	0	0
88	Outside Services	9230		265,074		0	0	0	0	0	0	0	0	(4,248)	0	0	0
89	Property Insurance	9240		187,108		0	0	0	0	0	0	0	0	26,737	0	0	0
90	Injuries & Damages	9250		1,168,245		0	0	0	0	0	0	0	0	211,383	0	0	0
91	Employee Pensions & Benefits	9260		5,120,758		0	0	0	0	0	233,410	0	0	(118,149)	0	0	0
92	Regulatory Commission Expenses	9280		228,922		0	0	0	66	0	0	0	0	0	0	0	0
93	Duplicate Charges- Credit	9290		0		0	0	0	0	0	0	0	0	0	0	0	0
94	General Advertising Expense	9301		10,076		0	0	0	0	0	0	0	0	0	0	0	0
95	Misc. General Expenses	9302		15,828,151		0	0	0	525,727	3,179	473,698	0	(501,921)	(3,097,933)	(5,509)	0	0
96	Rents	9310		1,451,795		0	0	0	0	0	0	0	0	0	(73,824)	0	0
97	Maintenace of General Plant	9320		238,296		0	0	0	0	0	0	0	0	0	0	0	0
98	Misc. General Expenses	9400's		0		0	0	0	0	0	0	0	0	0	0	0	0
99	Total A&G Operations			$28,212,839		$0	$0	$0	$953,480	$7,859	$707,108	$0	($501,921)	($2,977,234)	($79,333)	$0	$0
100	Total Operating Expense			$151,746,106		($75,042,680)	$0	$0	$1,777,410	$80,976	$766,309	($5,306)	($505,515)	($2,774,342)	($79,333)	$33,639	$58,580
101	Net Income before Income Tax			$26,757,019		$0	$5,318,354	$225,408	($1,777,410)	($80,976)	($766,309)	$5,306	$505,515	$2,774,342	$79,333	($33,639)	($58,580)

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
NOTE 1:	O&M Expense Detail		$51,624,395	$0	$0	$0	$1,777,410	$80,976	$707,108	$0	($501,921)	($2,804,692)	($79,333)	$0	$58,580
		Direct	19,453,598				425,054	72,948	740,264		(501,921)	1,548,667	0		58,580
		Shared	32,170,797				826,629	4,848	(635,410)			(3,936,798)	(73,824)		
		Distrigas					525,727	3,179	602,254			(416,561)	(5,509)		
			$51,624,395	$0	$0	$0	$1,777,410	$80,976	$707,108	$0	($501,921)	($2,804,692)	($79,333)	$0	$58,580

NOTE 2:	Account 407.3	336,151.92	
	Pension & OPEB	289,452.48	(Schedule G-7)
	Amortization expense of regulatory asset (GUD 10256)	46,699.44	(Schedule G-20)
		-	

WKP G.a.1

S SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF SERVICE AREA
IONTHS ENDED JUNE 30, 2019
FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

G REVENUE & EXPENSE ADJUSTMENTS

DESCRIPTION	ACCT. NO.	INJURIES & DAMAGES ADJ G-13	ADVERTISING ADJ G-14	DEPRECIATION ADJ G-15	AD VALOREM TAX ADJ G-16	TEXAS FRANCHISE TAX ADJ G-17	STORES LOAD ADJ G-18	TWE LOAD ADJ G-19	REGULATORY EXP ADJ G-20	DISTRIGAS % ADJ G-21	CONSERVATION PROGRAM REIMBURSMENT ADJ G-23	PIPELINE INTEGRITY TESTING EXPENSE ADJ G-24	HURRICANE HARVEY EXPENSE ADJ G-25	TOTAL ADJUSTMENTS	TEST YEAR ADJUSTED
		(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(w)	(x)	(y)	(z)
Revenue															
Gas Sales Revenue	480-482	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($69,724,326)	$96,912,395
Forfeited Discounts	4870	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Misc Fees	4880	0	0	0	0	0	0	0	0	0	0	0	0	277,029	2,415,023
Transportation	4893	0	0	0	0	0	0	0	0	0	0	0	0	357,875	9,676,789
Misc. Rent Revenue	4930	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Utility Revenue	4950	0	0	0	0	0	0	0	0	0	0	0	0	(409,496)	0
Total Revenue		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($69,498,918)	$109,004,207
Cost of Gas	805													($75,042,680)	$0
Deprec. & Amort. Expense															
Depreciation and Amortization Expense	4030-4050	$0	$0	$2,547,785	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,547,785	$21,351,137
Pension and OPEB Reg Asset Amortization Expense	4073	0	0	0	0	0	0	0	0	0	0	0	0	(5,306)	330,846
Total Depr. & Amort.		$0	$0	$2,547,785	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,542,480	$21,681,983
Taxes Other Than Income															
Payroll	4081	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$85,956	$1,299,721
Ad Valorem	4081	0	0	0	301,851	0	0	0	0	0	0	0	0	301,851	4,385,203
Revenue Related	4081	0	0	0	0	0	0	0	0	0	0	0	0	0	13,277
Other	4081	0	0	0	0	813,039	0	0	0	0	0	0	0	813,039	1,324,819
Total Taxes Other Than Income		$0	$0	$0	$301,851	$813,039	$0	$0	$0	$0	$0	$0	$0	$1,200,847	$7,023,021
Interest on Customer Deposits	4310	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$33,639	$150,792
Storage Misc.	8140-8360	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$200
Transmission & High Pressure Distribution															
Operation Supervision and Engineering	8500	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,194
Transmission Communication Equip	8520	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Compressor Station Labor and Expenses	8530	0	0	0	0	0	0	0	0	0	0	0	0	149	17,819
Mains Expenses	8560	0	0	0	0	0	0	6,824	0	0	0	276,480	0	297,795	912,715
Mains Expenses - OPC	8560	0	0	0	0	0	0	0	0	0	0	0	0	0	9,584
Measuring and Regulating Station Expenses	8570	0	0	0	0	0	0	0	0	0	0	0	0	24	1,571
Trans/Compression of Gas by Others	8580	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Expenses	8590	0	0	0	0	0	0	0	0	0	0	0	0	(4)	5,112
Rent	8600	0	0	0	0	0	0	0	0	0	0	0	0	0	2,919
Maintenance Supervison and Engineering	8610	0	0	0	0	0	0	0	0	0	0	0	0	0	6,860
Maintenance of Mains	8630	0	0	0	0	0	0	5	0	0	0	0	0	128	6,586
Maintenance of Mains - OPC	8630	0	0	0	0	0	0	0	0	0	0	0	0	0	147
Maintenance of Measuring and Regulating Station Equipment	8650	0	0	0	0	0	0	0	0	0	0	0	0	106	5,446
Maintenance of Communication Equipment	8660	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Transmission		$0	$0	$0	$0	$0	$0	$6,829	$0	$0	$0	$276,480	$0	$298,199	$971,953
Distribution Operations															
Supervision and Engineering	8700	$0	$0	$0	$0	$0	5	$3,052	$0	$0	$0	$0	$0	$44,777	$735,819
Distribution Load Dispatch	8710	0	0	0	0	0	0	0	0	0	0	0	0	33,895	260,199
Mains & Services	8740	0	0	0	0	0	4,439	30,838	0	0	0	0	119,065	202,526	4,081,513
Mains & Services - OPC	8740	0	0	0	0	0	0	0	0	0	0	0	0	0	164,077
Meas & Reg. Stat. Exp. - General	8750	0	0	0	0	0	1	4,672	0	0	0	0	0	17,594	442,921
Meas & Reg. Stat. Exp. - General - OPC	8750	0	0	0	0	0	0	0	0	0	0	0	0	0	6,750

WKP G.a.1

S SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF SERVICE AREA
IONTHS ENDED JUNE 30, 2019
FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

G REVENUE & EXPENSE ADJUSTMENTS

DESCRIPTION	ACCT. NO.	INJURIES & DAMAGES ADJ G-13	ADVERTISING ADJ G-14	DEPRECIATION ADJ G-15	AD VALOREM TAX ADJ G-16	TEXAS FRANCHISE TAX ADJ G-17	STORES LOAD ADJ G-18	TWE LOAD ADJ G-19	REGULATORY EXP ADJ G-20	DISTRIGAS % ADJ G-21	CONSERVATION PROGRAM REIMBURSMENT ADJ G-23	PIPELINE INTEGRITY TESTING EXPENSE ADJ G-24	HURRICANE HARVEY EXPENSE ADJ G-25	TOTAL ADJUSTMENTS	TEST YEAR ADJUSTED
		(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(w)	(x)	(y)	(z)
Meas & Reg. Stat. Exp. - Ind.	8760	0	0	0	0	0	0	413	0	0	0	0	0	7,041	67,660
Meas & Reg. Stat. Exp. - Ind. - OPC	8760	0	0	0	0	0	0	0	0	0	0	0	0	0	413
Meas & Reg. Stat. Exp. - City Gate	8770	0	0	0	0	0	5	13	0	0	0	0	0	485	3,791
Meas & Reg. Stat. Exp. - City Gate - OPC	8770	0	0	0	0	0	0	0	0	0	0	0	0	0	468
Meter & House Reg. Exp.	8780	0	0	0	0	0	4,036	114,421	0	0	0	0	0	278,738	4,347,169
Meter & House Reg. Exp. - OPC	8780	0	0	0	0	0	0	0	0	0	0	0	0	0	4
Customer Installation Exp	8790	0	0	0	0	0	0	3,553	0	0	0	0	0	8,196	84,335
Other Expense	8800	0	0	0	0	0	397	17,444	0	0	0	0	0	232,921	1,445,994
Other Expense - OPC	8800	0	0	0	0	0	0	0	0	0	0	0	0	0	132
Rents	8810	0	0	0	0	0	0	0	0	0	0	0	0	0	(188,295)
Corporate & TGS Division Expenses Credit	8820	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Distribution Operations		$0	$0	$0	$0	$0	$8,883	$174,407	$0	$0	$0	$0	$119,065	$826,172	$11,452,950
Distribution Maintenance															
Supervision and Engineering	8850	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$72
Struct. & Improv.	8860	0	0	0	0	0	0	0	0	0	0	0	0	0	362,515
Mains	8870	0	0	0	0	0	4,562	72,861	0	0	0	0	0	176,836	3,213,164
Mains - OPC	8870	0	0	0	0	0	0	0	0	0	0	0	0	0	100,539
Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0	0	25	10,144	0	0	0	0	0	25,222	412,851
Meas. & Reg. Stat. Exp. - Gen - OPC	8890	0	0	0	0	0	0	0	0	0	0	0	0	0	979
Meas. & Reg. Stat. Exp. - Ind.	8900	0	0	0	0	0	0	17,314	0	0	0	0	0	43,160	585,505
Meas. & Reg. Stat. Exp. - City Gate	8910	0	0	0	0	0	0	453	0	0	0	0	0	1,337	19,823
Maintenance of Services	8920	0	0	0	0	0	2,041	21,069	0	0	0	0	0	47,256	740,925
Meters & House Reg.	8930	0	0	0	0	0	0	47	0	0	0	0	0	397	7,092
Other Equipment	8940	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Clearing - Meter Shop - Small Meters	8950	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Clearing - Meter Shop - Large Meters	8960	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Distribution Maintenance		$0	$0	$0	$0	$0	$6,628	$121,887	$0	$0	$0	$0	$0	$294,207	$5,443,464
Total Distribution		$0	$0	$0	$0	$0	$15,512	$296,294	$0	$0	$0	$0	$119,065	$1,120,379	$16,896,414
Customer Accounting															
Supervision	9010	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16,700	$154,499
Meter Reading	9020	0	0	0	0	0	76	18,436	0	0	0	0	0	44,446	1,351,191
Customer Accounting	9030	0	0	0	0	0	0	6,217	0	0	0	0	0	282,316	4,115,966
Bad Debts	9040	0	0	0	0	0	0	0	0	0	0	0	0	58,580	585,680
Miscellaneous	9050	0	0	0	0	0	0	340	0	0	0	0	0	1,011	342,471
Total Customer Accounting		$0	$0	$0	$0	$0	$76	$24,993	$0	$0	$0	$0	$0	$403,053	$6,549,807
Customer Information															
Supervision	9070	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer Assistance Expense	9080	0	0	0	0	0	0	0	0	0	0	0	0	45,891	743,891
Inform. & Instruct. Adver. Exp.	9090	0	0	0	0	0	0	0	0	0	0	0	0	(104)	93,297
Customer Svc and Informational Svc	9100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Customer Information		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$45,787	$837,188
Sales															
Supervision	9110	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Demonstrating and Selling Expense	9120	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Advertising	9130	0	0	0	0	0	0	0	0	0	0	0	0	0	23,611
Employee Sales Referrals	9140	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Misc. Gas Sales Expense	9163	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Sales		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23,611

WKP G.a.1

S SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
GULF SERVICE AREA
MONTHS ENDED JUNE 30, 2019
FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

G REVENUE & EXPENSE ADJUSTMENTS

DESCRIPTION	ACCT. NO.	INJURIES & DAMAGES ADJ G-13	ADVERTISING ADJ G-14	DEPRECIATION ADJ G-15	AD VALOREM TAX ADJ G-16	TEXAS FRANCHISE TAX ADJ G-17	STORES LOAD ADJ G-18	TWE LOAD ADJ G-19	REGULATORY EXP ADJ G-20	DISTRIGAS % ADJ G-21	CONSERVATION PROGRAM REIMBURSMENT ADJ G-23	PIPELINE INTEGRITY TESTING EXPENSE ADJ G-24	HURRICANE HARVEY EXPENSE ADJ G-25	TOTAL ADJUSTMENTS	TEST YEAR ADJUSTED
		(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(w)	(x)	(y)	(z)
Total Customer Accounts Expense		$0	$0	$0	$0	$0	$76	$24,993	$0	$0	$0	$0	$0	$448,840	$7,410,606
Administrative & General															
Salaries	9200	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$432,367	$6,710,274
Office Supplies & Expenses	9210	0	0	0	0	0	0	445	0	0	0	0	0	5,420	1,543,903
Office Supplies & Expenses - OPC	9210	0	0	0	0	0	0	0	0	0	0	0	0	0	54
Transferred Credit	9220	0	0	0	0	0	0	0	0	0	0	0	0	0	(4,102,030)
Outside Services	9230	0	0	0	0	0	0	0	0	0	0	0	0	(4,248)	260,826
Property Insurance	9240	0	0	0	0	0	0	0	0	0	0	0	0	26,737	213,845
Injuries & Damages	9250	(124,868)	0	0	0	0	0	0	0	0	0	0	0	86,515	1,254,759
Employee Pensions & Benefits	9260	0	0	0	0	0	0	0	0	0	0	0	0	115,261	5,236,020
Regulatory Commission Expenses	9280	0	0	0	0	0	0	0	(27,241)	0	0	0	0	(27,176)	201,746
Duplicate Charges- Credit	9290	0	0	0	0	0	0	0	0	0	0	0	0	0	0
General Advertising Expense	9301	0	0	0	0	0	0	0	0	0	0	0	0	0	10,076
Misc. General Expenses	9302	0	0	0	0	0	0	0	0	140,112	0	0	0	(2,462,646)	13,365,505
Rents	9310	0	0	0	0	0	0	0	0	0	0	0	0	(73,824)	1,377,972
Maintenace of General Plant	9320	0	0	0	0	0	0	0	0	0	0	0	0	0	238,296
Misc. General Expenses	9400's	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total A&G Operations		($124,868)	$0	$0	$0	$0	$0	$445	($27,241)	$140,112	$0	$0	$0	($1,901,593)	$26,311,246
Total Operating Expense		($124,868)	$0	$2,547,785	$301,851	$813,039	$15,588	$328,562	($27,241)	$140,112	$0	$276,480	$119,065	($71,299,890)	$80,446,216
Net Income before Income Tax		$124,868	$0	($2,547,785)	($301,851)	($813,039)	($15,588)	($328,562)	$27,241	($140,112)	$0	($276,480)	($119,065)	$1,800,972	$28,557,991

O&M Expense Detail		($124,868)	$0	$0	$0	$0	$15,588	$328,562	($27,241)	$140,112	$0	$276,480	$119,065	($34,175)	$51,590,220
	Direct		0				15,588	328,562	(27,241)			276,480	119,065	3,056,046	22,509,644
	Shared	(124,868)												(3,939,424)	29,080,576
	Distrigas									140,112				849,203	
		($124,868)	$0	$0	$0	$0	$15,588	$328,562	($27,241)	$140,112	$0	$276,480	$119,065	($34,175)	$51,590,220

Account 407.3	336,151.92
Pension & OPEB	289,452.48
Amortization expense of regulatory asset (GUD 10256)	46,699.44
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WKP G.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	SERVICE AREA PER BOOKS	OPC PER BOOKS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS Note 1	TOTAL SERVICE AREA AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d)	(e) = (a) + (b) + (d)
	Revenue							
1	Gas Sales Revenue	480-482		$166,636,721	$0	$0	$0	$166,636,721
2	Forfeited Discounts	4870		0	0	0	0	0
3	Misc Fees	4880		2,137,994	0	0	0	2,137,994
4	Transportation	4893		9,318,914	0	0	0	9,318,914
5	Misc. Rent Revenue	4930		0	0	0	0	0
6	Other Utility Revenue	4950		409,496	0	0	0	409,496
7	Total Revenue			$178,503,125	$0	$0	$0	$178,503,125
8	Cost of Gas	805		$75,042,680	$0	$0	$0	$75,042,680
	Deprec. & Amort. Expense							
9	Depreciation and Amortization Expense	4030-4050		$16,455,342	$0	$5,050,231	$2,348,009	$18,803,351
10	Pension and OPEB Reg Asset Amortization Expense	4073		336,152	0	0	0	336,152
11	Total Depr. & Amort.			$16,791,494	$0	$5,050,231	$2,348,009	$19,139,503
	Taxes Other Than Income							
12	Payroll	4081		$0	$0	$2,610,635	$1,213,765	$1,213,765
13	Ad Valorem	4081	190	4,097,104	0	(29,580)	(13,752)	4,083,352
14	Revenue Related	4081	133, 138 & 140	13,277	0	0	0	13,277
15	Other	4081	131, 233 & 995	0	0	1,100,765	511,780	511,780
16	Total Taxes Other Than Income			$4,110,381	$0	$3,681,820	$1,711,792	$5,822,174
17	Interest on Customer Deposits	4310		$117,153	$0	$0	$0	$117,153
18	Storage Misc.	8140-8360		$0	$0	$430	$200	$200
	Transmission & High-Pressure Distribution							
19	Operation Supervision and Engineering	8500		$0	$0	$6,869	$3,194	$3,194
20	Transmission Communication Equip	8520		0	0	0	0	0
21	Compressor Station Labor and Expenses	8530		16,494	0	2,527	1,175	17,669
22	Mains Expenses	8560		443,161	0	369,429	171,759	614,920
23	Mains Expenses - OPC	8560		0	9,584	0	0	9,584
24	Measuring and Regulating Station Expenses	8570		1,224	0	695	323	1,547
25	Trans/Compression of Gas by Others	8580		0	0	0	0	0
26	Other Expenses	8590		2,588	0	5,437	2,528	5,116
27	Rent	8600		0	0	6,279	2,919	2,919
28	Maintenance Supervision and Engineering	8610		0	0	14,755	6,860	6,860
29	Maintenance of Mains	8630		4,793	0	3,582	1,665	6,458

WKP G.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	SERVICE AREA PER BOOKS	OPC PER BOOKS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS Note 1	TOTAL SERVICE AREA AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d)	(e) = (a) + (b) + (d)
30	Maintenance of Mains - OPC	8630		0	147	0	0	147
31	Maintenance of Measuring and Regulating Station Equipment	8650		4,569	0	1,659	771	5,340
32	Maintenance of Communication Equipment	8660		0	0	0	0	0
33	Total Transmission			$472,830	$9,731	$411,232	$191,194	$673,755
	Distribution Operations							
34	Supervision and Engineering	8700		$335,337	$0	$765,070	$355,705	$691,042
35	Distribution Load Dispatch	8710		0	0	486,747	226,304	226,304
36	Mains & Services	8740		3,841,608	0	80,396	37,379	3,878,987
37	Mains & Services - OPC	8740		0	164,077	0	0	164,077
38	Meas & Reg. Stat. Exp. - General	8750		387,596	0	81,154	37,731	425,328
39	Meas & Reg. Stat. Exp. - General - OPC	8750		0	6,750	0	0	6,750
40	Meas & Reg. Stat. Exp. - Ind.	8760		23,945	0	78,880	36,674	60,619
41	Meas & Reg. Stat. Exp. - Ind. - OPC	8760		0	413	0	0	413
42	Meas & Reg. Stat. Exp. - City Gate	8770		183	0	6,718	3,123	3,306
43	Meas & Reg. Stat. Exp. - City Gate - OPC	8770		0	468	0	0	468
44	Meter & House Reg. Exp.	8780		4,037,701	0	66,097	30,731	4,068,431
45	Meter & House Reg. Exp. - OPC	8780		0	4	0	0	4
46	Customer Installation Exp	8790		75,314	0	1,775	825	76,139
47	Other Expense	8800		1,098,242	0	246,985	114,831	1,213,073
48	Other Expense - OPC	8800		0	132	0	0	132
49	Rents	8810		(188,295)	0	0	0	(188,295)
50	Corporate & TGS Division Expenses Credit	8820		0	0	0	0	0
51	Total Distribution Operations			$9,611,631	$171,844	$1,813,824	$843,303	$10,626,778

WKP G.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	SERVICE AREA PER BOOKS	OPC PER BOOKS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS Note 1	TOTAL SERVICE AREA AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d)	(e) = (a) + (b) + (d)
	Distribution Maintenance							
52	Supervision and Engineering	8850		$72	$0	$0	$0	$72
53	Struct. & Improv.	8860		361,403	0	2,393	1,112	362,515
54	Mains	8870		2,837,617	0	427,400	198,712	3,036,329
55	Mains - OPC	8870		0	100,539	0	0	100,539
56	Meas. & Reg. Stat. Exp. - Gen	8890		394,959	0	(15,765)	(7,330)	387,629
57	Meas. & Reg. Stat. Exp. - Gen - OPC	8890		0	979	0	0	979
58	Meas. & Reg. Stat. Exp. - Ind.	8900		521,791	0	44,210	20,555	542,345
59	Meas. & Reg. Stat. Exp. - City Gate	8910		18,419	0	143	66	18,486
60	Maintenance of Services	8920		693,669	0	0	0	693,669
61	Meters & House Reg.	8930		6,695	0	0	0	6,695
62	Other Equipment	8940		0	0	0	0	0
63	Clearing - Meter Shop - Small Meters	8950		0	0	0	0	0
64	Clearing - Meter Shop - Large Meters	8960		0	0	0	0	0
65	Total Distribution Maintenance			$4,834,624	$101,518	$458,381	$213,116	$5,149,258
66	Total Distribution			$14,446,255	$273,362	$2,272,205	$1,056,419	$15,776,036
	Customer Accounting							
67	Supervision	9010		$0	$0	$296,386	$137,799	$137,799
68	Meter Reading	9020		1,307,228	0	(1,037)	(482)	1,306,746
69	Customer Accounting	9030		297,329	0	7,606,120	3,536,321	3,833,650
70	Bad Debts	9040		527,099	0	0	0	527,099
71	Miscellaneous	9050		14,120	0	704,061	327,340	341,460
72	Total Customer Accounting			$2,145,776	$0	$8,605,530	$4,000,978	$6,146,754
	Customer Information							
73	Supervision	9070		$0	$0	$0	$0	$0
74	Customer Assistance Expense	9080		509,832	0	404,723	188,168	698,000
75	Inform. & Instruct. Adver. Exp.	9090		0	0	200,893	93,401	93,401
76	Customer Svc and Informational Svc	9100		0	0	0	0	0
77	Total Customer Information			$509,832	$0	$605,616	$281,569	$791,401
	Sales							
78	Supervision	9110		$0	$0	$0	$0	$0
79	Demonstrating and Selling Expense	9120		0	0	0	0	0
80	Advertising	9130		21,501	0	4,538	2,110	23,611
81	Employee Sales Referrals	9140		0	0	0	0	0
82	Misc. Gas Sales Expense	9163		0	0	0	0	0

WKP G.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	SERVICE AREA PER BOOKS (a)	OPC PER BOOKS (b)	SHARED SERVICES INCLUDING DISTRIGAS (c)	ALLOCATED SHARED SERVICES PER BOOKS Note 1 (d)	TOTAL SERVICE AREA AND ALLOCATED SHARED SERVICES PER BOOKS (e) = (a) + (b) + (d)
83	Total Sales			$21,501	$0	$4,538	$2,110	$23,611
84	Total Customer Accounts Expense			$2,677,109	$0	$9,215,684	$4,284,657	$6,961,766
	Administrative & General							
85	Salaries	9200		$283,949	$0	$12,892,145	$5,993,958	$6,277,907
86	Office Supplies & Expenses	9210		591,582	0	2,036,649	946,901	1,538,483
87	Office Supplies & Expenses - OPC	9210		0	54	0	0	54
88	Transferred Credit	9220		0	0	(8,822,879)	(4,102,030)	(4,102,030)
89	Outside Services	9230		27,747	0	510,456	237,327	265,074
90	Property Insurance	9240		0	0	402,443	187,108	187,108
91	Injuries & Damages	9250		(269,885)	0	3,093,210	1,438,129	1,168,245
92	Employee Pensions & Benefits	9260		(295,675)	0	11,649,973	5,416,434	5,120,758
93	Regulatory Commission Expenses	9280		178,455	0	108,547	50,467	228,922
94	Duplicate Charges- Credit	9290		0	0	0	0	0
95	General Advertising Expenses	9301		9,954	0	262	122	10,076
96	Miscellaneous General Expenses	9302		365,608	0	33,257,715	15,462,543	15,828,151
97	Rents	9310		673,187	0	1,674,676	778,609	1,451,795
98	Maintenance of General Plant	9320		9,336	0	492,459	228,959	238,296
99	Misc. General Expenses	9400's		0	0	0	0	0
100	Total A&G Operations			$1,574,258	$54	$57,295,656	$26,638,527	$28,212,839
101	Total Operating Expense			$115,232,161	$283,146	$77,927,259	$36,230,798	$151,746,106
102	Net Income before Income Tax			$63,270,964	($283,146)	($77,927,259)	($36,230,798)	$26,757,019
				(Source 1)	(Source 1)	(Source 2)		

Note 1: Allocation Factor 0.464931

Source 1: WKP G.a.2 Op Inc Per Book CGSA TYE 6 2019 GL Detail rev exp acct (CONFIDENTIAL).xlsx
Source 2: WKP G.a.2.a1 Shared Service per book including Distrigas (CONFIDENTIAL) - CGSA.xlsx

WKP G.a.2.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
1	0	COMMON	4030	4030995	DEPR INDIRECT ALLOCATION	$0	$1,799,577	$0	$1,799,577
2	0	COMMON	4030	4030300	DEPR EXP-TEXAS 8.209 ACCRUAL	341	-	-	341
3	0	COMMON	4081	4081100	GEN TAX O/H TRF TO CAPITAL	(1,108,205)	-	-	(1,108,205)
4	0	COMMON	4081	4081101	GEN TAX FED UNEMPL INS TAX	39,368	-	-	39,368
5	0	COMMON	4081	4081102	GEN TAX FICA	3,959,788	-	-	3,959,788
6	0	COMMON	4081	4081131	GEN TAX SALES TAX ALLOWANCE	(40,342)	-	-	(40,342)
7	0	COMMON	4081	4081132	GEN TAX STATE UNEMPL INS	106,345	-	-	106,345
8	0	COMMON	4081	4081191	GEN TAX AD VALOREM RULE 8.209	-	-	-	-
9	0	COMMON	4081	4081190	GEN TAX AD VALOREM	(29,580)	-	-	(29,580)
10	0	COMMON	4091	4091100	CURRENT INCOME TAX ACCR	-	-	-	-
11	0	COMMON	4101	4101100	DEFERRED INCOME TAX ACCR	-	-	-	-
12	0	COMMON	4101	4101102	DEFERRED INCOME TAX AMORTIZATION EXCESS DTL	-	-	-	-
13	0	COMMON	4140	4140104	MISC UTILITY INCOME	-	-	-	-
14	0	COMMON	4140	4140230	MISC UTIL INCOME-DISTR	-	-	-	-
15	0	COMMON	4190	4190930	INT INCOME INTERCO	-	-	-	-
16	0	COMMON	4191	4191120	INT CAP AFTER CONSTRUC	-	-	-	-
17	0	COMMON	4210	4210100	MISC NONOPERATING INCOME	-	-	-	-
18	0	COMMON	4263	4263100	PENALTIES	-	-	-	-
19	0	COMMON	4300	4300901	ALLOC INTERCO INTEREST	-	-	-	-
20	0	COMMON	4310	4310901	ST DEBT INT EXP INTERCO	-	-	-	-
21	0	COMMON	4310	4310103	INT EXP CUSTOMER DEPOSITS	-	-	-	-
22	0	COMMON	4310	4310104	INT EXP TAX	-	-	-	-
23	0	COMMON	4320	4320100	INT CAP DURING CONSTRUC	-	-	-	-
24	0	COMMON	4320	4320101	INT CAP AFTER CONSTRUC	-	-	-	-
25	0	COMMON	8800	8800100	DISTR OTHER EXPENSES	(1,903)	-	-	(1,903)
26	0	COMMON	9080	9080100	CUST ASST MISC EXP	(1)	-	-	(1)
27	0	COMMON	9210	9210880	A&G S&E Auto-NSC	6,846	-	-	6,846
28	0	COMMON	9210	9210100	A&G SUPPLIES & EXPENSES MISC	0	-	-	0
29	0	COMMON	9210	9210411	A&G S&E TRAIN MGMT PROGRAM	-	-	-	-
30	0	COMMON	9260	9260902	A&G EMPL BEN O/H TRF CAPITAL	2,273	-	-	2,273
31	0	COMMON	9260	9260905	A&G EMPL BEN O/H TRF CAPITAL - NSC	38	-	-	38
32	1000	OGS GENERAL	4081	4081103	GEN TAX FICA INCENTIVE	303,699	-	-	303,699
33	1000	OGS GENERAL	8560	8560228	TRANS MAINS PERSONAL USE OF AUTO	34	-	-	34
34	1000	OGS GENERAL	8590	8590100	TRANS OTH MISC EXP	1,597	-	-	1,597
35	1000	OGS GENERAL	8740	8740207	DISTR MAINS & SVC TOOLS	22	-	-	22
36	1000	OGS GENERAL	8800	8800100	DISTR OTHER EXPENSES	263	-	-	263
37	1000	OGS GENERAL	9200	9200712	A&G SALARIES ESPP	247,778	-	-	247,778
38	1000	OGS GENERAL	9200	9200713	A&G SALARIES LT INCENT-RESTRICTED	239,509	-	-	239,509
39	1000	OGS GENERAL	9200	9200714	A&G SALARIES LT INCENT-PERFORMANCE	146,602	-	-	146,602
40	1000	OGS GENERAL	9200	9200700	A&G SALARIES INCENTIVE PLAN	3,954,894	-	-	3,954,894
41	1000	OGS GENERAL	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	31	-	-	31
42	1000	OGS GENERAL	9260	9260197	A&G EMPL BEN ACCR 401(K) CO MATCH - STI	195,142	-	-	195,142
43	1000	OGS GENERAL	9260	9260198	A&G EMPL BEN ACCR PSP ON STI	125,805	-	-	125,805
44	1000	OGS GENERAL	9260	9260312	A&G EMPL BEN STOCK RECEIVED	850	-	-	850
45	1000	OGS GENERAL	9302	9302106	A&G MISC AGA INDUSTRY DUES	77,047	-	-	77,047
46	1007	OGS ALLOCATIONS/DSTR	4030	4030995	DEPR INDIRECT ALLOCATION	-	-	2,615,646	2,615,646
47	1007	OGS ALLOCATIONS/DSTR	4081	4081995	GEN TAX DISTRIGAS ALLOCATION	-	-	1,141,107	1,141,107
48	1007	OGS ALLOCATIONS/DSTR	4171	4171995	OPER REV DISTRIGAS ALLOCATION	-	-	-	-
49	1007	OGS ALLOCATIONS/DSTR	4210	4210995	MISC NONOP INCOME DISTRIGAS ALLOCATION	-	-	-	-
50	1007	OGS ALLOCATIONS/DSTR	4265	4265995	MISC NONOP DISTRIGAS ALLOCATION	-	-	-	-
51	1007	OGS ALLOCATIONS/DSTR	9260	9260995	A&G EMPL BEN SERP DISTRIGAS ALLOC	-	-	433,199	433,199
52	1007	OGS ALLOCATIONS/DSTR	9260	9260996	A&G EMPL BEN PENSION DISTRIGAS	-	-	1,455,223	1,455,223
53	1007	OGS ALLOCATIONS/DSTR	9260	9260997	A&G EMPL BEN FAS 106 DISTRIGAS ALLOC	-	-	(25,593)	(25,593)

WKP G.a.2.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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SUPPORTING WORKPAPER FOR OPERATING REVENUE & EXPENSE PER BOOK, INCLUDING O&M EXPENSE FACTOR
FOR SHARED SERVICE, INCLUDING COSTS ALLOCATED ON A CAUSAL BASIS AND THROUGH DISTRIGAS

LINE NO.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
54	1007	OGS ALLOCATIONS/DSTR	9302	9302995	A&G MISC DISTRIGAS ALLOC	-	-	23,485,399	23,485,399
55	1010	OGS EXECUTIVE	4261	4261210	CIVIC EXPENSES - CONTRIBUTIONS	-	-	-	-
56	1010	OGS EXECUTIVE	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	798	-	-	798
57	1010	OGS EXECUTIVE	9210	9210201	A&G S&E ASSOC MTGS	398	-	-	398
58	1014	OGS CORP RESPONSIBILITY	9210	9210100	A&G SUPPLIES & EXPENSES MISC	144	-	-	144
59	1014	OGS CORP RESPONSIBILITY	9302	9302311	A&G MISC VWE (VOLUNTEERS WITH ENERGY)	279	-	-	279
60	1014	OGS COMMUNITY RELATIONS	8700	8700100	DISTR GEN SUPERVISION	-	-	-	-
61	1014	OGS COMMUNITY RELATIONS	9302	9302311	A&G MISC OGS VOLUNTEERS	12,972	-	-	12,972
62	1102	OGS SERVICE CONTRACT ADMINISTRATION	9230	9230120	A&G OUTSIDE SVC LEGAL	35,345	-	-	35,345
63	1106	OGS LEGAL TGS	9200	9200100	A&G SALARIES	259,141	-	-	259,141
64	1106	OGS LEGAL TGS	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	4,890	-	-	4,890
65	1106	OGS LEGAL TGS	9210	9210221	A&G S&E TRAINING & ED	6,472	-	-	6,472
66	1106	OGS LEGAL TGS	9210	9210100	A&G SUPPLIES & EXPENSES MISC	698	-	-	698
67	1106	OGS LEGAL TGS	9210	9210102	A&G S&E EMPL MISC	2,259	-	-	2,259
68	1106	OGS LEGAL TGS	9210	9210220	A&G S&E MEMBERSHIP DUES	1,221	-	-	1,221
69	1106	OGS LEGAL TGS	9230	9230120	A&G OUTSIDE SVC LEGAL	46,713	-	-	46,713
70	1106	OGS LEGAL TGS	9230	9230115	A&G OUTSIDE SVC LEGAL REGULATORY	80,754	-	-	80,754
71	1109	OGS LEGAL HUMAN RESOURCES	9210	9210221	A&G S&E TRAINING & ED	1,234	-	-	1,234
72	1109	OGS LEGAL HUMAN RESOURCES	9210	9210102	A&G S&E EMPL MISC	6,398	-	-	6,398
73	1109	OGS LEGAL HUMAN RESOURCES	9230	9230120	A&G OUTSIDE SVC LEGAL	4,117	-	-	4,117
74	1109	OGS LEGAL HUMAN RESOURCES	9250	9250200	A&G INJ & DAMAGES MISC SETTLEMENTS	45,000	-	-	45,000
75	1110	OGS LEGAL LITIGATION	9230	9230120	A&G OUTSIDE SVC LEGAL	49,188	-	-	49,188
76	1113	OGS ADMIN RISK & INS	9240	9240100	A&G PROPERTY INSURANCE	402,443	-	-	402,443
77	1113	OGS ADMIN RISK & INS	9250	9250100	A&G INSURANCE	38,625	-	-	38,625
78	1113	OGS ADMIN RISK & INS	9250	9250120	A&G INJ & DAMAGES WORKERS COMP	160,848	-	-	160,848
79	1113	OGS ADMIN RISK & INS	9250	9250180	A&G INJ & DAMAGES LIABILITY INSURANCE	2,167,722	-	-	2,167,722
80	1118	OGS ETHICS AND COMPLIANCE	9210	9210221	A&G S&E TRAINING & ED	1,559	-	-	1,559
81	1214	OGS FINANCIAL REPORTING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	10	-	-	10
82	1215	OGS TAXATION	9200	9200100	A&G SALARIES	90,110	-	-	90,110
83	1215	OGS TAXATION	9210	9210100	A&G SUPPLIES & EXPENSES MISC	3,103	-	-	3,103
84	1219	OGS TRAVEL, EXPENSE & VENDORS	8800	8800100	DISTR OTHER EXPENSES	3,050	-	-	3,050
85	1219	OGS TRAVEL, EXPENSE & VENDORS	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	0	-	-	0
86	1223	OGS ACCOUNTS PAYABLE	9200	9200100	A&G SALARIES	-	81,837	-	81,837
87	1223	OGS ACCOUNTS PAYABLE	9210	9210221	A&G S&E TRAINING & ED	-	(861)	-	(861)
88	1223	OGS ACCOUNTS PAYABLE	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	2,022	-	2,022
89	1223	OGS ACCOUNTS PAYABLE	9210	9210210	A&G S&E OFFICE SUPPLIES	-	24	-	24
90	1223	OGS ACCOUNTS PAYABLE	9210	9210220	A&G S&E MEMBERSHIP DUES	-	(125)	-	(125)
91	1223	OGS ACCOUNTS PAYABLE	9210	9210226	A&G S&E POSTAGE	-	6	-	6
92	1410	OGS INVESTOR RELATIONS	9210	9210223	A&G S&E AIRFARE	824	-	-	824
93	1419	OGS GOVT AFFAIRS TX	4264	4264102	GOVERNMENTAL AFFAIRS EXPENSE	-	-	-	-
94	1419	OGS GOVT AFFAIRS TX	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	1,192	-	-	1,192
95	1421	OGS INCLUSION & DIVERSITY	8800	8800100	DISTR OTHER EXPENSES	28	-	-	28
96	1421	OGS INCLUSION & DIVERSITY	9210	9210102	A&G S&E EMPL MISC	35	-	-	35
97	1508	OGS IT FINANCIAL MANAGEMENT	9210	9210210	A&G S&E OFFICE SUPPLIES	108	-	-	108
98	1512	OGS IT FIELD SERVICES	9200	9200100	A&G SALARIES	330,949	-	-	330,949
99	1512	OGS IT FIELD SERVICES	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	185	-	-	185
100	1514	OGS IT VOICE/DATA NETWORK	9210	9210301	A&G S&E TELE LONG DISTANCE	79,933	-	-	79,933
101	1514	OGS IT VOICE/DATA NETWORK	9210	9210303	A&G S&E TELE LOCAL LINES	31,699	-	-	31,699
102	1514	OGS IT VOICE/DATA NETWORK	9210	9210304	A&G S&E CELLULAR PHONES	162,284	-	-	162,284
103	1514	OGS IT VOICE/DATA NETWORK	9210	9210308	A&G S&E TELE DATA	126,371	-	-	126,371
104	1514	OGS IT VOICE/DATA NETWORK	9210	9210309	A&G S&E TELE SCADA	2,113	-	-	2,113
105	1515	OGS IT VOICE/DATA NETWORK SUPPORT	9200	9200100	A&G SALARIES	64,971	-	-	64,971
106	1515	OGS IT VOICE/DATA NETWORK SUPPORT	9210	9210221	A&G S&E TRAINING & ED	2,223	-	-	2,223

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
107	1515	OGS IT VOICE/DATA NETWORK SUPPORT	9320	9320140	A&G MNT AGREEMENT FEES	38,291	-	-	38,291
108	1521	OGS IT APPL DEV MEASUREMENT	9200	9200100	A&G SALARIES	98,591	-	-	98,591
109	1521	OGS IT APPL DEV MEASUREMENT	9320	9320140	A&G MNT AGREEMENT FEES	129,598	-	-	129,598
110	1527	OGS IT CALL CENTER APPLICATIONS	9320	9320140	A&G MNT AGREEMENT FEES	2,700	-	-	2,700
111	1529	OGS CYBER SECURITY	9230	9230302	A&G OUTSIDE SVC IT APPLICATION SUPPORT	3,030	-	-	3,030
112	1530	OGS PHYSICAL SECURITY	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	3	-	-	3
113	1530	OGS PHYSICAL SECURITY	9320	9320140	A&G MNT AGREEMENT FEES	604	-	-	604
114	1532	OGS IT NATURAL GAS TRANSP/STORAGE &	9320	9320140	A&G MNT AGREEMENT FEES	47,217	-	-	47,217
115	1534	OGS IT APPL BILLING	9200	9200100	A&G SALARIES	65,860	92,623	-	158,484
116	1534	OGS IT APPL BILLING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	1,779	-	1,779
117	1534	OGS IT APPL BILLING	9210	9210221	A&G S&E TRAINING & ED	-	2,794	-	2,794
118	1534	OGS IT APPL BILLING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	46	-	46
119	1534	OGS IT APPL BILLING	9210	9210417	A&G S&E VISA/IMMIGRATION AND NATIONALITY COSTS	-	3,342	-	3,342
120	1534	OGS IT APPL BILLING	9230	9230302	A&G OUTSIDE SVC IT APPLICATION SUPPORT	-	110,579	-	110,579
121	1534	OGS IT APPL BILLING	9230	9230307	A&G OUTSIDE SVC CLOUD COMPUTING	-	21,625	-	21,625
122	1534	OGS IT APPL BILLING	9302	9302120	A&G MISC EMPL MOVING	-	16,818	-	16,818
123	1534	OGS IT APPL BILLING	9320	9320140	A&G MNT AGREEMENT FEES	379	260,565	-	260,944
124	1537	OGS IT APPL HR CORPORATE	9200	9200100	A&G SALARIES	83	134,977	-	135,060
125	1537	OGS IT APPL HR CORPORATE	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	143	222,518	-	222,662
126	1600	OGS HR EXEC	9200	9200100	A&G SALARIES	70	179,661	-	179,732
127	1600	OGS HR EXEC	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	0	15,160	-	15,160
128	1612	OGS COMP & BEN EXEC	9200	9200100	A&G SALARIES	90	97,280	-	97,370
129	1612	OGS COMP & BEN EXEC	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	-	2,890	-	2,890
130	1620	OGS WORKFORCE DEVELOPMENT PLANS	9210	9210221	A&G S&E TRAINING & ED	691	-	-	691
131	1620	OGS WORKFORCE DEVELOPMENT PLANS	9210	9210100	A&G SUPPLIES & EXPENSES MISC	325	-	-	325
132	1620	OGS WORKFORCE DEVELOPMENT PLANS	9210	9210411	A&G S&E TRAIN MGMT PROGRAM	51,938	-	-	51,938
133	1620	OGS WORKFORCE DEVELOPMENT PLANS	9210	9210412	A&G S&E EMPL TRAINING PROGRAM	1,768	-	-	1,768
134	1620	OGS WORKFORCE DEVELOPMENT PLANS	9210	9210809	A&G S&E EMPLOYEE ONBOARDING PROGRAM	30,238	-	-	30,238
135	1620	OGS WORKFORCE DEVELOPMENT PLANS	9260	9260310	A&G EMPL BEN SVC RECOGNITION	55,600	-	-	55,600
136	1620	OGS WORKFORCE DEVELOPMENT PLANS	9260	9260302	A&G EMPL BEN TUITION LOANS	60,706	-	-	60,706
137	1620	OGS WORKFORCE DEVELOPMENT PLANS	9260	9260321	A&G EMPL BEN DRUG & ALCOHOL TESTING	36	-	-	36
138	1620	OGS WORKFORCE DEVELOPMENT PLANS	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	72	264,258	-	264,330
139	1621	OGS HR PLAN ADMINISTRATION	9260	9260102	A&G EMPL BEN 401(K) ADMIN	-	53,104	-	53,104
140	1621	OGS HR PLAN ADMINISTRATION	9260	9260112	A&G EMPL BEN SERP ADMIN	-	153	-	153
141	1621	OGS HR PLAN ADMINISTRATION	9260	9260115	A&G EMPL BEN PENSION ADMIN	22,538	(13,865)	-	8,673
142	1621	OGS HR PLAN ADMINISTRATION	9260	9260140	A&G EMPL BEN PROFIT SHARING ADMIN	-	57,219	-	57,219
143	1621	OGS HR PLAN ADMINISTRATION	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	20	51,316	-	51,336
144	1622	OGS HEALTH & WELFARE	9260	9260190	A&G EMPL BEN RESERVE	8,693,355	-	-	8,693,355
145	1622	OGS HEALTH & WELFARE	9260	9260192	A&G EMPL BEN RESERVE IBNR	(478,400)	-	-	(478,400)
146	1622	OGS HEALTH & WELFARE	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	(1)	38,371	-	38,370
147	1623	OGS RETIREMENT BENEFITS	9260	9260101	A&G EMPL BEN 401(K) CO MATCH	2,586,102	-	-	2,586,102
148	1623	OGS RETIREMENT BENEFITS	9260	9260103	A&G EMPL BEN DEF COMP CO MATCH	1,508	-	-	1,508
149	1623	OGS RETIREMENT BENEFITS	9260	9260141	A&G EMPL BEN PROFIT SHARING	1,787,315	-	-	1,787,315
150	1623	OGS RETIREMENT BENEFITS	9260	9260413	A&G EMPL BEN ACTUARY ONE GAS PENSION-SC	2,377,484	-	-	2,377,484
151	1623	OGS RETIREMENT BENEFITS	9260	9260431	A&G EMPL BEN ACTUARY OPEB-SC	86,489	-	-	86,489
152	1623	OGS RETIREMENT BENEFITS	9260	9260511	A&G EMPL BEN ACTUARY SERP-NSC	7,589	-	-	7,589
153	1623	OGS RETIREMENT BENEFITS	9260	9260513	A&G EMPL BEN ACTUARY ONE GAS PENSION-NSC	1,711,315	-	-	1,711,315
154	1623	OGS RETIREMENT BENEFITS	9260	9260531	A&G EMPL BEN ACTUARY OPEB-NSC	51,431	-	-	51,431
155	1626	OGS BENEFITS	9200	9200100	A&G SALARIES	47	135,061	-	135,108
156	1626	OGS BENEFITS	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	2	6,964	-	6,967
157	1627	OGS PAYROLL & BENEFITS ACCOUNTING	9200	9200100	A&G SALARIES	83	165,350	-	165,432
158	1627	OGS PAYROLL & BENEFITS ACCOUNTING	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	5	5,514	-	5,518
159	1630	OGS BENEFIT WELLNESS PROGRAM	9200	9200100	A&G SALARIES	-	10,280	-	10,280

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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SUPPORTING WORKPAPER FOR OPERATING REVENUE & EXPENSE PER BOOK, INCLUDING O&M EXPENSE FACTOR
FOR SHARED SERVICE, INCLUDING COSTS ALLOCATED ON A CAUSAL BASIS AND THROUGH DISTRIGAS

LINE NO.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
160	1630	OGS BENEFIT WELLNESS PROGRAM	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	-	17	-	17
161	1631	OGS COMPENSATION	9200	9200100	A&G SALARIES	37	100,311	-	100,349
162	1631	OGS COMPENSATION	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	(9)	34,881	-	34,871
163	1634	OGS BUSINESS PARTNERS	9200	9200100	A&G SALARIES	20,825	5,785	-	26,610
164	1634	OGS BUSINESS PARTNERS	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	2,658	-	-	2,658
165	1634	OGS BUSINESS PARTNERS	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	-	457	-	457
166	1635	OGS PROFESSIONAL DEVELOPMENT TRAINING	9200	9200100	A&G SALARIES	-	1,065	-	1,065
167	1635	OGS PROFESSIONAL DEVELOPMENT TRAINING	9210	9210411	A&G S&E TRAIN MGMT PROGRAM	-	-	-	-
168	1635	OGS PROFESSIONAL DEVELOPMENT TRAINING	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	-	13,344	-	13,344
169	1636	OGS STAFFING & RECRUITING	9200	9200100	A&G SALARIES	74	154,186	-	154,260
170	1636	OGS STAFFING & RECRUITING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	222	-	-	222
171	1636	OGS STAFFING & RECRUITING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	612	-	-	612
172	1636	OGS STAFFING & RECRUITING	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	136	122,224	-	122,361
173	1637	OGS WORKFORCE DEVELOPMENT	9200	9200100	A&G SALARIES	88	161,086	-	161,174
174	1637	OGS WORKFORCE DEVELOPMENT	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	4,226	-	-	4,226
175	1637	OGS WORKFORCE DEVELOPMENT	9210	9210221	A&G S&E TRAINING & ED	2,163	-	-	2,163
176	1637	OGS WORKFORCE DEVELOPMENT	9210	9210809	A&G S&E EMPLOYEE ONBOARDING PROGRAM	-	-	-	-
177	1637	OGS WORKFORCE DEVELOPMENT	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	7	47,057	-	47,064
178	1638	OGS HUMAN RELATIONS	9200	9200100	A&G SALARIES	114	239,133	-	239,247
179	1638	OGS HUMAN RELATIONS	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	2	29,061	-	29,062
180	1642	OGS SAFETY	8740	8740225	DISTR MAINS & SVC UNIFORMS	543	-	-	543
181	1642	OGS SAFETY	8750	8750100	DISTR MEAS & REG ST MISC	83	-	-	83
182	1642	OGS SAFETY	8800	8800100	DISTR OTHER EXPENSES	3,707	-	-	3,707
183	1642	OGS SAFETY	8800	8800400	DISTR OTH SAFETY	101	-	-	101
184	1642	OGS SAFETY	9050	9050120	CUST ACCTS SVC BLDG	171	-	-	171
185	1642	OGS SAFETY	9200	9200100	A&G SALARIES	250,986	-	-	250,986
186	1642	OGS SAFETY	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	12,380	-	-	12,380
187	1642	OGS SAFETY	9210	9210221	A&G S&E TRAINING & ED	5,587	-	-	5,587
188	1642	OGS SAFETY	9210	9210100	A&G SUPPLIES & EXPENSES MISC	162,107	-	-	162,107
189	1642	OGS SAFETY	9210	9210210	A&G S&E OFFICE SUPPLIES	311	-	-	311
190	1642	OGS SAFETY	9210	9210102	A&G S&E EMPL MISC	4,271	-	-	4,271
191	1642	OGS SAFETY	9210	9210220	A&G S&E MEMBERSHIP DUES	797	-	-	797
192	1642	OGS SAFETY	9210	9210222	A&G S&E LODGING	8,587	-	-	8,587
193	1642	OGS SAFETY	9210	9210223	A&G S&E AIRFARE	4,032	-	-	4,032
194	1642	OGS SAFETY	9210	9210226	A&G S&E POSTAGE	127	-	-	127
195	1642	OGS SAFETY	9210	9210228	A&G S&E PERS USE AUTO	9	-	-	9
196	1642	OGS SAFETY	9210	9210400	A&G S&E SAFETY	4,316	-	-	4,316
197	1642	OGS SAFETY	9260	9260307	A&G EMPL BEN EMPLOYEE EVENTS	3,350	-	-	3,350
198	1642	OGS SAFETY	9310	9310100	A&G RENTS LAND/FACILITY	77	-	-	77
199	1709	OGS RECORDS & INFORMATION MANAGEMENT	9230	9230110	A&G OUTSIDE SVC MISC	8,752	-	-	8,752
200	1710	OGS MATERIALS MANAGEMENT SERVICES	8780	8780100	DISTR MEAS & HOUSE REG MISC	-	2,502	-	2,502
201	1710	OGS MATERIALS MANAGEMENT SERVICES	9200	9200100	A&G SALARIES	-	2,752	-	2,752
202	1710	OGS MATERIALS MANAGEMENT SERVICES	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	545	-	545
203	1710	OGS MATERIALS MANAGEMENT SERVICES	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	14	-	14
204	1714	OGS ENVIRONMENTAL MGMT	9210	9210100	A&G SUPPLIES & EXPENSES MISC	50	-	-	50
205	1714	OGS ENVIRONMENTAL MGMT	9210	9210209	A&G S&E ENVIRONMENTAL EXP	4,707	-	-	4,707
206	1714	OGS ENVIRONMENTAL MGMT	9230	9230110	A&G OUTSIDE SVC MISC	(31,976)	-	-	(31,976)
207	1715	OGS CENTRAL METER SHOP	8780	8780100	DISTR MEAS & HOUSE REG MISC	-	48,735	-	48,735
208	1715	OGS CENTRAL METER SHOP	8780	8780139	DISTR MEAS & HOUSE MEAS SVC CTR	-	14,350	-	14,350
209	1715	OGS CENTRAL METER SHOP	8860	8860120	DISTR MNT STRUC & IMPROV SVC BLDG	-	221	-	221
210	1715	OGS CENTRAL METER SHOP	9200	9200100	A&G SALARIES	-	6,700	-	6,700
211	1715	OGS CENTRAL METER SHOP	9210	9210402	A&G S&E OTH BLDG OPER	-	27,531	-	27,531
212	1716	OGS RIGHT OF WAY MGMT	9200	9200100	A&G SALARIES	81,835	19,509	-	101,344

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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SUPPORTING WORKPAPER FOR OPERATING REVENUE & EXPENSE PER BOOK, INCLUDING O&M EXPENSE FACTOR FOR SHARED SERVICE, INCLUDING COSTS ALLOCATED ON A CAUSAL BASIS AND THROUGH DISTRIGAS

LINE NO.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
213	1716	OGS RIGHT OF WAY MGMT	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	2,181	506	-	2,687
214	1716	OGS RIGHT OF WAY MGMT	9210	9210221	A&G S&E TRAINING & ED	265	1,316	-	1,581
215	1716	OGS RIGHT OF WAY MGMT	9210	9210100	A&G SUPPLIES & EXPENSES MISC	792	2,324	-	3,116
216	1716	OGS RIGHT OF WAY MGMT	9210	9210102	A&G S&E EMPL MISC	-	505	-	505
217	1716	OGS RIGHT OF WAY MGMT	9210	9210220	A&G S&E MEMBERSHIP DUES	-	93	-	93
218	1716	OGS RIGHT OF WAY MGMT	9210	9210223	A&G S&E AIRFARE	-	159	-	159
219	1716	OGS RIGHT OF WAY MGMT	9210	9210226	A&G S&E POSTAGE	-	13	-	13
220	1716	OGS RIGHT OF WAY MGMT	9210	9210202	A&G S&E SUBS/PUBLICATIONS	-	584	-	584
221	1716	OGS RIGHT OF WAY MGMT	9210	9210404	A&G S&E MAIL ROOM	-	29	-	29
222	1716	OGS RIGHT OF WAY MGMT	9210	9210240	A&G S&E PERMITS/FEES/ASSESSMENTS	-	8	-	8
223	1716	OGS RIGHT OF WAY MGMT	9210	9210228	A&G S&E PERS USE AUTO	43	28	-	71
224	1716	OGS RIGHT OF WAY MGMT	9302	9302100	A&G MISC EXPENSES	797	282	-	1,080
225	1716	OGS RIGHT OF WAY MGMT	9302	9302409	A&G MISC	-	5	-	5
226	1750	OGS BUSINESS CONTINUITY	9200	9200100	A&G SALARIES	-	50,881	-	50,881
227	1750	OGS BUSINESS CONTINUITY	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	3,262	-	3,262
228	1750	OGS BUSINESS CONTINUITY	9210	9210221	A&G S&E TRAINING & ED	-	3,352	-	3,352
229	1750	OGS BUSINESS CONTINUITY	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	885	-	885
230	1750	OGS BUSINESS CONTINUITY	9210	9210220	A&G S&E MEMBERSHIP DUES	-	156	-	156
231	1750	OGS BUSINESS CONTINUITY	9210	9210201	A&G S&E ASSOC MTGS	-	188	-	188
232	1750	OGS BUSINESS CONTINUITY	9230	9230110	A&G OUTSIDE SVC MISC	-	5,360	-	5,360
233	1901	OGS FIELD OPERATIONS EXECUTIVE	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	3	-	-	3
234	1901	OGS FIELD OPERATIONS EXECUTIVE	9210	9210100	A&G SUPPLIES & EXPENSES MISC	82	-	-	82
235	1910	OGS BILLING CONTROL GROUP	9200	9200100	A&G SALARIES	-	137,142	-	137,142
236	1910	OGS BILLING CONTROL GROUP	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	23	-	23
237	1910	OGS BILLING CONTROL GROUP	9210	9210221	A&G S&E TRAINING & ED	-	103	-	103
238	1910	OGS BILLING CONTROL GROUP	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	1,899	-	1,899
239	1910	OGS BILLING CONTROL GROUP	9210	9210210	A&G S&E OFFICE SUPPLIES	-	151	-	151
240	1910	OGS BILLING CONTROL GROUP	9210	9210220	A&G S&E MEMBERSHIP DUES	-	138	-	138
241	1911	OGS PLANT ACCOUNTING	9200	9200100	A&G SALARIES	19,806	962	-	20,769
242	1911	OGS PLANT ACCOUNTING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	313	-	313
243	1911	OGS PLANT ACCOUNTING	9210	9210221	A&G S&E TRAINING & ED	-	2,986	-	2,986
244	1911	OGS PLANT ACCOUNTING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	341	-	341
245	1911	OGS PLANT ACCOUNTING	9210	9210210	A&G S&E OFFICE SUPPLIES	-	557	-	557
246	1911	OGS PLANT ACCOUNTING	9210	9210220	A&G S&E MEMBERSHIP DUES	-	174	-	174
247	1911	OGS PLANT ACCOUNTING	9210	9210201	A&G S&E ASSOC MTGS	-	53	-	53
248	1911	OGS PLANT ACCOUNTING	9210	9210240	A&G S&E PERMITS/FEES/ASSESSMENTS	-	95	-	95
249	1916	OGS ENGINEERING EXECUTIVE	8560	8560250	TRANS MAIN PIPELINE INTEGRITY MANAGEMENT	-	288	-	288
250	1916	OGS ENGINEERING EXECUTIVE	8560	8560250	TRANS MAINS PIPELINE INTEGRITY MANAGEMENT	-	55	-	55
251	1916	OGS ENGINEERING EXECUTIVE	8700	8700100	DISTR GEN SUPERVISION	-	54,009	-	54,009
252	1916	OGS ENGINEERING EXECUTIVE	8740	8740250	DISTR MAINS & SVC DISTR INTEGRITY MGMT PROGRAM	-	356	-	356
253	1916	OGS ENGINEERING EXECUTIVE	8800	8800100	DISTR OTHER EXPENSES	-	12,902	-	12,902
254	1916	OGS ENGINEERING EXECUTIVE	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	487	-	487
255	1916	OGS ENGINEERING EXECUTIVE	9210	9210221	A&G S&E TRAINING & ED	-	228	-	228
256	1916	OGS ENGINEERING EXECUTIVE	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	1,282	-	1,282
257	1916	OGS ENGINEERING EXECUTIVE	9210	9210304	A&G S&E CELLULAR PHONES	-	27	-	27
258	1917	OGS RESOURCE MGMT EXECUTIVE	4261	4261210	CIVIC EXPENSES - CONTRIBUTIONS	-	-	-	-
259	1917	OGS RESOURCE MGMT EXECUTIVE	8700	8700100	DISTR GEN SUPERVISION	-	47,129	-	47,129
260	1917	OGS RESOURCE MGMT EXECUTIVE	8700	8700228	DISTR GEN SUPER PERS USE AUTO	-	545	-	545
261	1917	OGS RESOURCE MGMT EXECUTIVE	8780	8780100	DISTR MEAS & HOUSE REG MISC	-	2	-	2
262	1917	OGS RESOURCE MGMT EXECUTIVE	9200	9200100	A&G SALARIES	-	49,674	-	49,674
263	1917	OGS RESOURCE MGMT EXECUTIVE	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	1,948	-	1,948
264	1917	OGS RESOURCE MGMT EXECUTIVE	9210	9210221	A&G S&E TRAINING & ED	-	139	-	139
265	1917	OGS RESOURCE MGMT EXECUTIVE	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	423	-	423

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SUPPORTING WORKPAPER FOR OPERATING REVENUE & EXPENSE PER BOOK, INCLUDING O&M EXPENSE FACTOR FOR SHARED SERVICE, INCLUDING COSTS ALLOCATED ON A CAUSAL BASIS AND THROUGH DISTRIGAS

LINE NO.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
266	1917	OGS RESOURCE MGMT EXECUTIVE	9210	9210220	A&G S&E MEMBERSHIP DUES	-	223	-	223
267	1917	OGS RESOURCE MGMT EXECUTIVE	9210	9210201	A&G S&E ASSOC MTGS	-	1,621	-	1,621
268	1917	OGS RESOURCE MGMT EXECUTIVE	9210	9210228	A&G S&E PERS USE AUTO	-	131	-	131
269	1919	OGS CUSTOMER SERVICE EXECUTIVE	9030	9030110	CUST RECORDS EXPENSE	-	49	-	49
270	1919	OGS CUSTOMER SERVICE EXECUTIVE	9030	9030228	CUST REC/COLLEC EXP PERS USE AUTO	-	5	-	5
271	1919	OGS CUSTOMER SERVICE EXECUTIVE	9050	9050100	CUST ACCTS MISC EXP	-	4	-	4
272	1919	OGS CUSTOMER SERVICE EXECUTIVE	9080	9080100	CUST ASST MISC EXP	-	9	-	9
273	1919	OGS CUSTOMER SERVICE EXECUTIVE	9200	9200100	A&G SALARIES	-	190,383	-	190,383
274	1919	OGS CUSTOMER SERVICE EXECUTIVE	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	283	7,484	-	7,767
275	1919	OGS CUSTOMER SERVICE EXECUTIVE	9210	9210221	A&G S&E TRAINING & ED	-	1,713	-	1,713
276	1919	OGS CUSTOMER SERVICE EXECUTIVE	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	6,043	-	6,043
277	1919	OGS CUSTOMER SERVICE EXECUTIVE	9210	9210210	A&G S&E OFFICE SUPPLIES	-	66	-	66
278	1919	OGS CUSTOMER SERVICE EXECUTIVE	9210	9210228	A&G S&E PERS USE AUTO	-	127	-	127
279	1919	OGS CUSTOMER SERVICE EXECUTIVE	9230	9230110	A&G OUTSIDE SVC MISC	-	32,672	-	32,672
280	1920	OGS RATES & REGULATORY EXECUTIVE	9210	9210221	A&G S&E TRAINING & ED	202	-	-	202
281	1926	OGS AM STRATEGY	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	683	-	-	683
282	1926	OGS AM STRATEGY	9210	9210809	A&G S&E EMPLOYEE ONBOARDING PROGRAM	287	-	-	287
283	1926	OGS RM TECHNOLOGY	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	1,795	-	-	1,795
284	1930	OGS RM WORKFORCE STRATEGY & PLANNING	9200	9200100	A&G SALARIES	-	29,100	-	29,100
285	1930	OGS RM WORKFORCE STRATEGY & PLANNING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	4,792	-	4,792
286	1930	OGS RM WORKFORCE STRATEGY & PLANNING	9210	9210221	A&G S&E TRAINING & ED	-	1,185	-	1,185
287	1930	OGS RM WORKFORCE STRATEGY & PLANNING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	9	-	9
288	1931	OGS RM RESOURCE SUPPLY	9200	9200100	A&G SALARIES	-	88,723	-	88,723
289	1931	OGS RM RESOURCE SUPPLY	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	4,130	-	4,130
290	1931	OGS RM RESOURCE SUPPLY	9210	9210221	A&G S&E TRAINING & ED	-	1,334	-	1,334
291	1931	OGS RM RESOURCE SUPPLY	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	213	-	213
292	1931	OGS RM RESOURCE SUPPLY	9210	9210210	A&G S&E OFFICE SUPPLIES	-	19	-	19
293	1931	OGS RM RESOURCE SUPPLY	9210	9210220	A&G S&E MEMBERSHIP DUES	-	1,236	-	1,236
294	1931	OGS RM RESOURCE SUPPLY	9210	9210404	A&G S&E MAIL ROOM	-	22	-	22
295	1931	OGS RM RESOURCE SUPPLY	9210	9210201	A&G S&E ASSOC MTGS	-	5,266	-	5,266
296	1931	OGS RM RESOURCE SUPPLY	9302	9302311	A&G MISC OGS VOLUNTEERS	-	3	-	3
297	1932	OGS RM CONTRACTOR CTRL & OPTIMIZATION	8800	8800400	DISTR OTH SAFETY	20	-	-	20
298	1932	OGS RM CONTRACTOR CTRL & OPTIMIZATION	9200	9200100	A&G SALARIES	32,894	24,551	-	57,445
299	1932	OGS RM CONTRACTOR CTRL & OPTIMIZATION	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	12,012	2,362	-	14,374
300	1932	OGS RM CONTRACTOR CTRL & OPTIMIZATION	9210	9210221	A&G S&E TRAINING & ED	3,959	230	-	4,189
301	1932	OGS RM CONTRACTOR CTRL & OPTIMIZATION	9210	9210100	A&G SUPPLIES & EXPENSES MISC	83	1,255	-	1,338
302	1932	OGS RM CONTRACTOR CTRL & OPTIMIZATION	9210	9210201	A&G S&E ASSOC MTGS	-	233	-	233
303	1932	OGS RM CONTRACTOR CTRL & OPTIMIZATION	9210	9210413	A&G S&E TECH/CUST SVC TRAINING	-	40,060	-	40,060
304	1933	OGS RM PROJECTS & PROGRAM DELIVERY	9200	9200100	A&G SALARIES	26,768	14,670	-	41,438
305	1933	OGS RM PROJECTS & PROGRAM DELIVERY	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	10,777	4,205	-	14,981
306	1933	OGS RM PROJECTS & PROGRAM DELIVERY	9210	9210221	A&G S&E TRAINING & ED	-	3,496	-	3,496
307	1933	OGS RM PROJECTS & PROGRAM DELIVERY	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	17	-	17
308	1933	OGS RM PROJECTS & PROGRAM DELIVERY	9210	9210220	A&G S&E MEMBERSHIP DUES	-	166	-	166
309	1934	OGS RM SERVICES	9200	9200100	A&G SALARIES	-	27,483	-	27,483
310	1934	OGS RM SERVICES	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	84	-	84
311	1934	OGS RM SERVICES	9210	9210221	A&G S&E TRAINING & ED	-	14	-	14
312	1934	OGS RM SERVICES	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	641	-	641
313	1935	OGS CENTRAL ENGINEERING	8500	8500100	TRANS GEN SUPERVISION	-	6,869	-	6,869
314	1935	OGS CENTRAL ENGINEERING	8610	8610100	TRANS MNT GEN SUPERVISION	-	1,951	-	1,951
315	1935	OGS CENTRAL ENGINEERING	8700	8700100	DISTR GEN SUPERVISION	-	44,264	-	44,264
316	1935	OGS CENTRAL ENGINEERING	8740	8740250	DISTR MAINS & SVC DISTR INTEGRITY MGMT	-	702	-	702
317	1935	OGS CENTRAL ENGINEERING	8740	8740250	DISTR MAINS & SVC DISTR INTEGRITY MGMT PROGRAM	-	498	-	498
318	1935	OGS CENTRAL ENGINEERING	9200	9200100	A&G SALARIES	-	1,951	-	1,951

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LINE NO.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
319	1935	OGS CENTRAL ENGINEERING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	936	-	936
320	1935	OGS CENTRAL ENGINEERING	9210	9210221	A&G S&E TRAINING & ED	-	6,278	-	6,278
321	1935	OGS CENTRAL ENGINEERING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	36	-	36
322	1935	OGS CENTRAL ENGINEERING	9210	9210220	A&G S&E MEMBERSHIP DUES	-	113	-	113
323	1935	OGS CENTRAL ENGINEERING	9210	9210222	A&G S&E LODGING	-	627	-	627
324	1935	OGS CENTRAL ENGINEERING	9210	9210223	A&G S&E AIRFARE	-	416	-	416
325	1935	OGS CENTRAL ENGINEERING	9210	9210228	A&G S&E PERS USE AUTO	-	33	-	33
326	1936	OGS ENG P/L INTEGRITY MGMT	8230	8230110	STRG GAS LOSSES	430	-	-	430
327	1936	OGS ENG P/L INTEGRITY MGMT	8560	8560100	TRANS MAIN MISC EXP	-	879	-	879
328	1936	OGS ENG P/L INTEGRITY MGMT	8560	8560100	TRANS MAINS MISC EXP	-	77	-	77
329	1936	OGS ENG P/L INTEGRITY MGMT	8560	8560250	TRANS MAIN PIPELINE INTEGRITY MANAGEMENT	52,653	66,341	-	118,994
330	1936	OGS ENG P/L INTEGRITY MGMT	8560	8560250	TRANS MAINS PIPELINE INTEGRITY MANAGEMENT	68,293	65,831	-	134,124
331	1936	OGS ENG P/L INTEGRITY MGMT	8560	8560245	TRANS MAINS LINE PIGGING	494	118	-	611
332	1936	OGS ENG P/L INTEGRITY MGMT	8600	8600100	TRANS RENT	-	6,279	-	6,279
333	1936	OGS ENG P/L INTEGRITY MGMT	8610	8610100	TRANS MNT GEN SUPERVISION	-	12,804	-	12,804
334	1936	OGS ENG P/L INTEGRITY MGMT	8700	8700100	DISTR GEN SUPERVISION	12,337	6,585	-	18,921
335	1936	OGS ENG P/L INTEGRITY MGMT	8740	8740250	DISTR MAINS & SVC DISTR INTEGRITY MGMT	12,027	21,871	-	33,897
336	1936	OGS ENG P/L INTEGRITY MGMT	8740	8740250	DISTR MAINS & SVC DISTR INTEGRITY MGMT PROGRAM	12,647	23,985	-	36,632
337	1936	OGS ENG P/L INTEGRITY MGMT	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	99	-	99
338	1936	OGS ENG P/L INTEGRITY MGMT	9210	9210221	A&G S&E TRAINING & ED	639	158	-	797
339	1936	OGS ENG P/L INTEGRITY MGMT	9210	9210100	A&G SUPPLIES & EXPENSES MISC	185	-	-	185
340	1936	OGS ENG P/L INTEGRITY MGMT	9210	9210102	A&G S&E EMPL MISC	77	-	-	77
341	1936	OGS ENG P/L INTEGRITY MGMT	9210	9210220	A&G S&E MEMBERSHIP DUES	-	65	-	65
342	1936	OGS ENG P/L INTEGRITY MGMT	9210	9210417	A&G S&E VISA/IMMIGRATION AND NATIONALITY COSTS	-	2,693	-	2,693
343	1936	OGS ENG P/L INTEGRITY MGMT	9210	9210349	A&G S&E VALIDATED PARKING	35	-	-	35
344	1937	OGS ENG REG COMPLIANCE & TRAINING	8700	8700100	DISTR GEN SUPERVISION	-	31,621	-	31,621
345	1937	OGS ENG REG COMPLIANCE & TRAINING	8800	8800100	DISTR OTHER EXPENSES	-	12,719	-	12,719
346	1937	OGS ENG REG COMPLIANCE & TRAINING	9210	9210221	A&G S&E TRAINING & ED	-	158	-	158
347	1938	OGS ENG QUALITY AND COMPLIANCE	8560	8560100	TRANS MAINS MISC EXP	112,717	-	-	112,717
348	1938	OGS ENG QUALITY AND COMPLIANCE	8700	8700100	DISTR GEN SUPERVISION	101,927	54,973	-	156,900
349	1938	OGS ENG QUALITY AND COMPLIANCE	8700	8700228	DISTR GEN SUPER PERS USE AUTO	-	402	-	402
350	1938	OGS ENG QUALITY AND COMPLIANCE	9200	9200100	A&G SALARIES	-	1,586	-	1,586
351	1938	OGS ENG QUALITY AND COMPLIANCE	9210	9210221	A&G S&E TRAINING & ED	-	158	-	158
352	1938	OGS ENG QUALITY AND COMPLIANCE	9210	9210100	A&G SUPPLIES & EXPENSES MISC	76,050	109,396	-	185,445
353	1938	OGS ENG QUALITY AND COMPLIANCE	9210	9210404	A&G S&E MAIL ROOM	-	15	-	15
354	1938	OGS ENG QUALITY AND COMPLIANCE	9301	9301150	A&G ADVERTISING ONLINE	-	3	-	3
355	1938	OGS ENG QUALITY AND COMPLIANCE	9302	9302311	A&G MISC VWE (VOLUNTEERS WITH ENERGY)	-	127	-	127
356	1939	OGS RM WORK MANAGEMENT	8740	8740100	DISTR MAINS & SVC MISC	256	-	-	256
357	1939	OGS RM WORK MANAGEMENT	8740	8740225	DISTR MAINS & SVC UNIFORMS	-	61	-	61
358	1939	OGS RM WORK MANAGEMENT	8800	8800100	DISTR OTHER EXPENSES	-	3	-	3
359	1939	OGS RM WORK MANAGEMENT	8800	8800210	DISTR OTH OFFICE SUPPLIES	-	97	-	97
360	1939	OGS RM WORK MANAGEMENT	9200	9200100	A&G SALARIES	-	218,391	-	218,391
361	1939	OGS RM WORK MANAGEMENT	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	44,970	-	44,970
362	1939	OGS RM WORK MANAGEMENT	9210	9210221	A&G S&E TRAINING & ED	-	1,124	-	1,124
363	1939	OGS RM WORK MANAGEMENT	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	310	-	310
364	1939	OGS RM WORK MANAGEMENT	9210	9210210	A&G S&E OFFICE SUPPLIES	-	39	-	39
365	1939	OGS RM WORK MANAGEMENT	9210	9210222	A&G S&E LODGING	-	31	-	31
366	1939	OGS RM WORK MANAGEMENT	9210	9210223	A&G S&E AIRFARE	-	231	-	231
367	1939	OGS RM WORK MANAGEMENT	9210	9210202	A&G S&E SUBS/PUBLICATIONS	-	15	-	15
368	1939	OGS RM WORK MANAGEMENT	9210	9210201	A&G S&E ASSOC MTGS	-	2,223	-	2,223
369	1939	OGS RM WORK MANAGEMENT	9210	9210203	A&G S&E UTILITIES	-	6	-	6
370	1943	OGS CUSTOMER DEVELOPMENT	9080	9080100	CUST ASST MISC EXP	1,349	-	-	1,349
371	1943	OGS COMMERCIAL PROJECT MANAGEMENT	9210	9210221	A&G S&E TRAINING & ED	3,400	-	-	3,400

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
372	1944	OGS CUSTOMER SERVICE SUPPORT	9030	9030210	CUST REC/COLLEC OFFICE SUPPLIES	-	71	-	71
373	1944	OGS CUSTOMER SERVICE SUPPORT	9030	9030100	CUST REC/COLLEC EXP MISC	-	100	-	100
374	1944	OGS CUSTOMER SERVICE SUPPORT	9030	9030110	CUST RECORDS EXPENSE	-	41	-	41
375	1944	OGS CUSTOMER SERVICE SUPPORT	9050	9050100	CUST ACCTS MISC EXP	3,116	700,124	-	703,240
376	1944	OGS CUSTOMER SERVICE SUPPORT	9200	9200100	A&G SALARIES	-	(2,074)	-	(2,074)
377	1944	OGS CUSTOMER SERVICE SUPPORT	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	68	-	68
378	1951	OGS CONTRACTOR SOURCING	9200	9200100	A&G SALARIES	-	17,699	-	17,699
379	1951	OGS CONTRACTOR SOURCING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	-	5,194	-	5,194
380	1951	OGS CONTRACTOR SOURCING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	98	-	98
381	1953	OGS PROCESS IMPROVEMENT & CUSTOMER	9030	9030100	CUST REC/COLLEC EXP MISC	-	102	-	102
382	1953	OGS PROCESS IMPROVEMENT & CUSTOMER	9050	9050100	CUST ACCTS MISC EXP	-	1	-	1
383	1953	OGS PROCESS IMPROVEMENT & CUSTOMER	9200	9200100	A&G SALARIES	-	117,466	-	117,466
384	1953	OGS PROCESS IMPROVEMENT & CUSTOMER	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	(0)	7,456	-	7,456
385	1953	OGS PROCESS IMPROVEMENT & CUSTOMER	9210	9210221	A&G S&E TRAINING & ED	-	665	-	665
386	1953	OGS PROCESS IMPROVEMENT & CUSTOMER	9210	9210100	A&G SUPPLIES & EXPENSES MISC	-	82	-	82
387	1953	OGS PROCESS IMPROVEMENT & CUSTOMER	9210	9210210	A&G S&E OFFICE SUPPLIES	-	10	-	10
388	1953	OGS PROCESS IMPROVEMENT & CUSTOMER	9210	9210220	A&G S&E MEMBERSHIP DUES	-	68	-	68
389	1953	OGS PROCESS IMPROVEMENT & CUSTOMER	9210	9210201	A&G S&E ASSOC MTGS	-	456	-	456
390	1953	OGS PROCESS IMPROVEMENT & CUSTOMER	9230	9230110	A&G OUTSIDE SVC MISC	-	18,801	-	18,801
391	1953	OGS PROCESS IMPROVEMENT & CUSTOMER	9302	9302311	A&G MISC OGS VOLUNTEERS	-	6	-	6
392	2000	ONG GENERAL	8560	8560100	TRANS MAIN MISC EXP	860	-	-	860
393	2000	ONG GENERAL	8560	8560100	TRANS MAINS MISC EXP	362	-	-	362
394	2000	ONG GENERAL	8560	8560228	TRANS MAINS PERSONAL USE OF AUTO	126	-	-	126
395	2000	ONG GENERAL	8590	8590100	TRANS OTH MISC EXP	3,313	-	-	3,313
396	2510	ONG CUSTOMER BILLING	9030	9030100	CUST REC/COLLEC EXP MISC	1,062	-	-	1,062
397	2510	ONG CUSTOMER BILLING	9030	9030110	CUST RECORDS EXPENSE	3,933	-	-	3,933
398	2515	ONG CREDIT & COLLECTIONS	9030	9030100	CUST REC/COLLEC EXP MISC	5,022	-	-	5,022
399	2521	ONG WEB WORK	9030	9030110	CUST RECORDS EXPENSE	2	-	-	2
400	2622	ONG BUSINESS DEV GROWTH	9080	9080100	CUST ASST MISC EXP	(0)	-	-	(0)
401	2625	ONG COMMERCIAL PROJECT MANAGEMENT	9080	9080100	CUST ASST MISC EXP	60	-	-	60
402	2625	ONG COMMERCIAL PROJECT MANAGEMENT	9210	9210226	A&G S&E POSTAGE	131	-	-	131
403	2628	ONG BUILDER HOTLINE	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	137	-	-	137
404	3000	KGS GENERAL	8590	8590100	TRANS OTH MISC EXP	362	-	-	362
405	3000	KGS GENERAL	8630	8630250	TRANS MNT MAINS PIPELINE INTEGRITY MANAGEMENT	58	-	-	58
406	7000	TGS GENERAL	4030	4030100	DEPRECIATION EXPENSE	624,645	-	-	624,645
407	7000	TGS GENERAL	4043	4043100	AMORT OF GAS PLANT	10,023	-	-	10,023
408	7000	TGS GENERAL	4081	4081100	GEN TAX O/H TRF TO CAPITAL	(690,360)	-	-	(690,360)
409	7000	TGS GENERAL	4210	4210100	MISC NONOPERATING INCOME	-	-	-	-
410	7000	TGS GENERAL	4263	4263100	PENALTIES	-	-	-	-
411	7000	TGS GENERAL	4264	4264102	GOVERNMENTAL AFFAIRS EXPENSE	-	-	-	-
412	7000	TGS GENERAL	4265	4265101	MISCELLANEOUS NONOPERATING EXPENSES	-	-	-	-
413	7000	TGS GENERAL	4310	4310100	MISC INTEREST EXP	-	-	-	-
414	7000	TGS GENERAL	4800	4800111	UTIL GAS SALES RES UNBILLED	-	-	-	-
415	7000	TGS GENERAL	4810	4810111	UTIL GAS SALES COMM UNBILLED	-	-	-	-
416	7000	TGS GENERAL	4810	4810211	UTIL GAS SALES IND UNBILLED	-	-	-	-
417	7000	TGS GENERAL	4820	4820111	UTIL GAS SALES CITY GATE UNBILLED	-	-	-	-
418	7000	TGS GENERAL	4880	4880100	SVC REVENUE MISC	-	-	-	-
419	7000	TGS GENERAL	4950	4950300	OTH GAS REV UTIL MISC	-	-	-	-
420	7000	TGS GENERAL	8040	8040100	NATURAL GAS CITY GATE PURCHASES	-	-	-	-
421	7000	TGS GENERAL	8050	8050108	OTH GAS PURCH RESIDENTIAL UNBILLED	-	-	-	-
422	7000	TGS GENERAL	8050	8050134	OTH GAS PURCH UNBILLED COMM	-	-	-	-
423	7000	TGS GENERAL	8050	8050144	OTH GAS PURCH UNBILLED IND	-	-	-	-
424	7000	TGS GENERAL	8050	8050208	OTH GAS PURCH PUBLIC AUTHORITY UNBILLED	-	-	-	-

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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FOR SHARED SERVICE, INCLUDING COSTS ALLOCATED ON A CAUSAL BASIS AND THROUGH DISTRIGAS

LINE NO.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
425	7000	TGS GENERAL	8051	8051100	OTH GAS PURCH UNRECOV GAS ADJ	-	-	-	-
426	7000	TGS GENERAL	8710	8710100	DISTR LOAD DISPATCHING	485,303	-	-	485,303
427	7000	TGS GENERAL	8710	8710228	DISTR LOAD PERS USE AUTO	1,445	-	-	1,445
428	7000	TGS GENERAL	8740	8740100	DISTR MAINS & SVC MISC	180	-	-	180
429	7000	TGS GENERAL	8740	8740207	DISTR MAINS & SVC TOOLS	10	-	-	10
430	7000	TGS GENERAL	8760	8760100	DISTR IND MEAS & REG ST MISC	45,945	-	-	45,945
431	7000	TGS GENERAL	8770	8770100	DISTR C G MEAS & REG ST MISC	4,543	-	-	4,543
432	7000	TGS GENERAL	8800	8800100	DISTR OTHER EXPENSES	8,620	-	-	8,620
433	7000	TGS GENERAL	8800	8800226	DISTR OTH POSTAGE	57	-	-	57
434	7000	TGS GENERAL	8870	8870100	DISTR MNT MAINS MISC	263,033	-	-	263,033
435	7000	TGS GENERAL	9020	9020228	MTR READ PERS USE AUTO	21	-	-	21
436	7000	TGS GENERAL	9210	9210100	A&G SUPPLIES & EXPENSES MISC	(370)	-	-	(370)
437	7000	TGS GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES	76,646	-	-	76,646
438	7000	TGS GENERAL	9210	9210304	A&G S&E CELLULAR PHONES	62,958	-	-	62,958
439	7000	TGS GENERAL	9210	9210308	A&G S&E TELE DATA	41,921	-	-	41,921
440	7000	TGS GENERAL	9210	9210807	A&G S&E TRANSITION COSTS	23,416	-	-	23,416
441	7000	TGS GENERAL	9220	9220902	A&G TRF TO CONSTRUCTION	(8,822,879)	-	-	(8,822,879)
442	7000	TGS GENERAL	9230	9230110	A&G OUTSIDE SVC MISC	50,685	-	-	50,685
443	7000	TGS GENERAL	9230	9230810	A&G OUTSIDE SVC CONTRACT	11,667	-	-	11,667
444	7000	TGS GENERAL	9260	9260902	A&G EMPL BEN O/H TRF CAPITAL	(6,903,732)	-	-	(6,903,732)
445	7000	TGS GENERAL	9260	9260905	A&G EMPL BEN O/H TRF CAPITAL - NSC	(696,277)	-	-	(696,277)
446	7000	TGS GENERAL	9302	9302901	A&G MISC O/H TRF TO AFFIL	1,793,790	-	-	1,793,790
447	7000	TGS GENERAL	9302	9302100	A&G MISC EXPENSES	3	-	-	3
448	7000	TGS GENERAL	9302	9302800	A&G MISC PROCUREMENT CARD CLEARING	47,117	-	-	47,117
449	7000	TGS GENERAL	9302	9302915	A&G MISC ROYALTY ALLOCATED	6,924,897	-	-	6,924,897
450	7000	TGS GENERAL	9310	9310120	A&G RENTS EQUIPMENT	29,446	-	-	29,446
451	7000	TGS GENERAL	9320	9320140	A&G MNT AGREEMENT FEES	8,947	-	-	8,947
452	7010	TGS EXECUTIVE	4261	4261213	CIVIC EXPENSES - PROFESSIONAL ASSOCIATIONS	-	-	-	-
453	7010	TGS EXECUTIVE	4265	4265101	MISCELLANEOUS NONOPERATING EXPENSES	-	-	-	-
454	7010	TGS EXECUTIVE	8700	8700100	DISTR GEN SUPERVISION	12,667	-	-	12,667
455	7010	TGS EXECUTIVE	8800	8800100	DISTR OTHER EXPENSES	2,808	-	-	2,808
456	7010	TGS EXECUTIVE	9200	9200100	A&G SALARIES	188,025	-	-	188,025
457	7010	TGS EXECUTIVE	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	12,801	-	-	12,801
458	7010	TGS EXECUTIVE	9210	9210221	A&G S&E TRAINING & ED	13,673	-	-	13,673
459	7010	TGS EXECUTIVE	9210	9210100	A&G SUPPLIES & EXPENSES MISC	6,087	-	-	6,087
460	7010	TGS EXECUTIVE	9210	9210220	A&G S&E MEMBERSHIP DUES	40	-	-	40
461	7010	TGS EXECUTIVE	9210	9210201	A&G S&E ASSOC MTGS	2,258	-	-	2,258
462	7010	TGS EXECUTIVE	9302	9302105	A&G MISC INDUSTRY DUES	5,900	-	-	5,900
463	7012	TGS CLAIMS	8740	8740100	DISTR MAINS & SVC MISC	46	-	-	46
464	7012	TGS CLAIMS	8780	8780100	DISTR MEAS & HOUSE REG MISC	10	-	-	10
465	7012	TGS CLAIMS	9200	9200100	A&G SALARIES	329,518	-	-	329,518
466	7012	TGS CLAIMS	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	8,694	-	-	8,694
467	7012	TGS CLAIMS	9210	9210221	A&G S&E TRAINING & ED	3,561	-	-	3,561
468	7012	TGS CLAIMS	9210	9210100	A&G SUPPLIES & EXPENSES MISC	17,897	-	-	17,897
469	7012	TGS CLAIMS	9210	9210210	A&G S&E OFFICE SUPPLIES	86	-	-	86
470	7012	TGS CLAIMS	9210	9210102	A&G S&E EMPL MISC	673	-	-	673
471	7012	TGS CLAIMS	9210	9210220	A&G S&E MEMBERSHIP DUES	283	-	-	283
472	7012	TGS CLAIMS	9210	9210202	A&G S&E SUBS/PUBLICATIONS	736	-	-	736
473	7012	TGS CLAIMS	9210	9210201	A&G S&E ASSOC MTGS	3,602	-	-	3,602
474	7012	TGS CLAIMS	9210	9210101	A&G S&E ADMIN	2,849	-	-	2,849
475	7012	TGS CLAIMS	9210	9210240	A&G S&E PERMITS/FEES/ASSESSMENTS	933	-	-	933
476	7012	TGS CLAIMS	9230	9230120	A&G OUTSIDE SVC LEGAL	1,661	-	-	1,661
477	7012	TGS CLAIMS	9230	9230110	A&G OUTSIDE SVC MISC	29,492	-	-	29,492

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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SUPPORTING WORKPAPER FOR OPERATING REVENUE & EXPENSE PER BOOK, INCLUDING O&M EXPENSE FACTOR
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LINE NO.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
478	7012	TGS CLAIMS	9250	9250120	A&G INJ & DAMAGES WORKERS COMP	288,031	-	-	288,031
479	7012	TGS CLAIMS	9250	9250140	A&G INJ & DAMAGES 3RD PARTY VEHICLE ACCIDENT	12,092	-	-	12,092
480	7012	TGS CLAIMS	9250	9250200	A&G INJ & DAMAGES MISC SETTLEMENTS	380,892	-	-	380,892
481	7012	TGS CLAIMS	9302	9302120	A&G MISC EMPL MOVING	13,971	-	-	13,971
482	7014	TGS COMMUNITY RELATIONS	4261	4261210	CIVIC EXPENSES - CONTRIBUTIONS	-	-	-	-
483	7014	TGS COMMUNITY RELATIONS	4261	4261225	DONATIONS-OTHER 501 (C)(3)	-	-	-	-
484	7014	TGS COMMUNITY RELATIONS	8800	8800226	DISTR OTH POSTAGE	39	-	-	39
485	7014	TGS COMMUNITY RELATIONS	9200	9200100	A&G SALARIES	22,293	-	-	22,293
486	7014	TGS COMMUNITY RELATIONS	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	7,834	-	-	7,834
487	7014	TGS COMMUNITY RELATIONS	9210	9210221	A&G S&E TRAINING & ED	823	-	-	823
488	7014	TGS COMMUNITY RELATIONS	9210	9210100	A&G SUPPLIES & EXPENSES MISC	163	-	-	163
489	7014	TGS COMMUNITY RELATIONS	9302	9302105	A&G MISC INDUSTRY DUES	25	-	-	25
490	7016	TGS TECHNICAL TRAINING	8740	8740225	DISTR MAINS & SVC UNIFORMS	726	-	-	726
491	7016	TGS TECHNICAL TRAINING	8800	8800100	DISTR OTHER EXPENSES	11	-	-	11
492	7016	TGS TECHNICAL TRAINING	9200	9200100	A&G SALARIES	557,861	-	-	557,861
493	7016	TGS TECHNICAL TRAINING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	60,493	-	-	60,493
494	7016	TGS TECHNICAL TRAINING	9210	9210221	A&G S&E TRAINING & ED	14,538	-	-	14,538
495	7016	TGS TECHNICAL TRAINING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	21,482	-	-	21,482
496	7016	TGS TECHNICAL TRAINING	9210	9210210	A&G S&E OFFICE SUPPLIES	14,331	-	-	14,331
497	7016	TGS TECHNICAL TRAINING	9210	9210102	A&G S&E EMPL MISC	162	-	-	162
498	7016	TGS TECHNICAL TRAINING	9210	9210413	A&G S&E TECH/CUST SVC TRAINING	11,141	-	-	11,141
499	7017	TGS CREDIT & COLLECTIONS	8800	8800400	DISTR OTH SAFETY	78	-	-	78
500	7017	TGS CREDIT & COLLECTIONS	9010	9010100	CUST ACCTG/COLL SUPERVISION	78,426	-	-	78,426
501	7017	TGS CREDIT & COLLECTIONS	9030	9030100	CUST REC/COLLEC EXP MISC	766,069	-	-	766,069
502	7017	TGS CREDIT & COLLECTIONS	9030	9030110	CUST RECORDS EXPENSE	3,234	-	-	3,234
503	7017	TGS CREDIT & COLLECTIONS	9030	9030170	CUST COLLEC AGENCY FEE	55,077	-	-	55,077
504	7017	TGS CREDIT & COLLECTIONS	9030	9030226	CUST REC/COLLEC POSTAGE	697	-	-	697
505	7017	TGS CREDIT & COLLECTIONS	9030	9030130	CUST COLLECTION EXPENSE	830	-	-	830
506	7018	TGS CUSTOMER BILLING	9010	9010100	CUST ACCTG/COLL SUPERVISION	848	-	-	848
507	7018	TGS CUSTOMER BILLING	9030	9030210	CUST REC/COLLEC OFFICE SUPPLIES	293,974	-	-	293,974
508	7018	TGS CUSTOMER BILLING	9030	9030100	CUST REC/COLLEC EXP MISC	280,677	-	-	280,677
509	7018	TGS CUSTOMER BILLING	9030	9030110	CUST RECORDS EXPENSE	551,803	-	-	551,803
510	7018	TGS CUSTOMER BILLING	9030	9030226	CUST REC/COLLEC POSTAGE	2,309,777	-	-	2,309,777
511	7018	TGS CUSTOMER BILLING	9050	9050228	CUST ACCTS PERS USE AUTO	235	-	-	235
512	7018	TGS CUSTOMER BILLING	9280	9280100	A&G REG COMMISSION EXP	-	-	-	-
513	7019	TGS SYSTEMS SUPPORT	9050	9050100	CUST ACCTS MISC EXP	-	-	-	-
514	7021	TGS INFORMATION CENTER	9010	9010100	CUST ACCTG/COLL SUPERVISION	1,175	-	-	1,175
515	7021	TGS INFORMATION CENTER	9030	9030100	CUST REC/COLLEC EXP MISC	14,708	-	-	14,708
516	7021	TGS INFORMATION CENTER	9030	9030110	CUST RECORDS EXPENSE	2,225,894	-	-	2,225,894
517	7021	TGS INFORMATION CENTER	9050	9050100	CUST ACCTS MISC EXP	288	-	-	288
518	7021	TGS INFORMATION CENTER	9210	9210100	A&G SUPPLIES & EXPENSES MISC	1,506	-	-	1,506
519	7021	TGS INFORMATION CENTER	9210	9210809	A&G S&E EMPLOYEE ONBOARDING PROGRAM	20	-	-	20
520	7022	TGS PRICING	9200	9200100	A&G SALARIES	886,346	-	-	886,346
521	7022	TGS PRICING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	7,371	-	-	7,371
522	7022	TGS PRICING	9210	9210221	A&G S&E TRAINING & ED	28,192	-	-	28,192
523	7022	TGS PRICING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	970	-	-	970
524	7022	TGS PRICING	9210	9210102	A&G S&E EMPL MISC	246	-	-	246
525	7022	TGS PRICING	9210	9210220	A&G S&E MEMBERSHIP DUES	150	-	-	150
526	7022	TGS PRICING	9210	9210222	A&G S&E LODGING	683	-	-	683
527	7022	TGS PRICING	9210	9210223	A&G S&E AIRFARE	315	-	-	315
528	7022	TGS PRICING	9210	9210412	A&G S&E EMPL TRAINING PROGRAM	303	-	-	303
529	7022	TGS PRICING	9210	9210349	A&G S&E VALIDATED PARKING	101	-	-	101
530	7022	TGS PRICING	9230	9230110	A&G OUTSIDE SVC MISC	13,062	-	-	13,062

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						(a)	(b)	(c)	(d)
531	7022	TGS PRICING	9280	9280100	A&G REG COMMISSION EXP	108,547	-	-	108,547
532	7022	TGS PRICING	9302	9302120	A&G MISC EMPL MOVING	(6,000)	-	-	(6,000)
533	7025	TGS FINANCIAL PLANNING	9200	9200100	A&G SALARIES	286,826	-	-	286,826
534	7025	TGS FINANCIAL PLANNING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	904	-	-	904
535	7025	TGS FINANCIAL PLANNING	9210	9210102	A&G S&E EMPL MISC	58	-	-	58
536	7025	TGS FINANCIAL PLANNING	9210	9210240	A&G S&E PERMITS/FEES/ASSESSMENTS	66	-	-	66
537	7025	TGS FINANCIAL PLANNING	9210	9210809	A&G S&E EMPLOYEE ONBOARDING PROGRAM	21	-	-	21
538	7028	TGS GENERAL ACCOUNTING	9200	9200100	A&G SALARIES	312,405	-	-	312,405
539	7028	TGS GENERAL ACCOUNTING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	4,747	-	-	4,747
540	7028	TGS GENERAL ACCOUNTING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	1,215	-	-	1,215
541	7028	TGS GENERAL ACCOUNTING	9210	9210222	A&G S&E LODGING	223	-	-	223
542	7028	TGS GENERAL ACCOUNTING	9210	9210223	A&G S&E AIRFARE	254	-	-	254
543	7028	TGS GENERAL ACCOUNTING	9302	9302120	A&G MISC EMPL MOVING	14,336	-	-	14,336
544	7032	TGS FACILITIES MANAGEMENT	8740	8740225	DISTR MAINS & SVC UNIFORMS	232	-	-	232
545	7032	TGS FACILITIES MANAGEMENT	8800	8800100	DISTR OTHER EXPENSES	9,992	-	-	9,992
546	7032	TGS FACILITIES MANAGEMENT	8800	8800120	DISTR OTH SVC BLDG	82	-	-	82
547	7032	TGS FACILITIES MANAGEMENT	8860	8860120	DISTR MNT STRUC & IMPROV SVC BLDG	2,086	-	-	2,086
548	7032	TGS FACILITIES MANAGEMENT	9050	9050120	CUST ACCTS SVC BLDG	25	-	-	25
549	7032	TGS FACILITIES MANAGEMENT	9200	9200100	A&G SALARIES	289,133	-	-	289,133
550	7032	TGS FACILITIES MANAGEMENT	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	11,745	-	-	11,745
551	7032	TGS FACILITIES MANAGEMENT	9210	9210100	A&G SUPPLIES & EXPENSES MISC	24,605	-	-	24,605
552	7032	TGS FACILITIES MANAGEMENT	9210	9210210	A&G S&E OFFICE SUPPLIES	17	-	-	17
553	7032	TGS FACILITIES MANAGEMENT	9210	9210220	A&G S&E MEMBERSHIP DUES	-	-	-	-
554	7032	TGS FACILITIES MANAGEMENT	9210	9210404	A&G S&E MAIL ROOM	36,716	-	-	36,716
555	7032	TGS FACILITIES MANAGEMENT	9210	9210402	A&G S&E OTH BLDG OPER	109,694	-	-	109,694
556	7032	TGS FACILITIES MANAGEMENT	9310	9310100	A&G RENTS LAND/FACILITY	1,346,146	-	-	1,346,146
557	7033	TGS GAS SUPPLY	4265	4265101	MISCELLANEOUS NONOPERATING EXPENSES	-	-	-	-
558	7033	TGS GAS SUPPLY	8870	8870101	DISTR MNT MAINS CATHODIC PROTECT	824	-	-	824
559	7033	TGS GAS SUPPLY	9080	9080100	CUST ASST MISC EXP	89	-	-	89
560	7033	TGS GAS SUPPLY	9200	9200100	A&G SALARIES	1,108,442	-	-	1,108,442
561	7033	TGS GAS SUPPLY	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	16,756	-	-	16,756
562	7033	TGS GAS SUPPLY	9210	9210221	A&G S&E TRAINING & ED	5,049	-	-	5,049
563	7033	TGS GAS SUPPLY	9210	9210100	A&G SUPPLIES & EXPENSES MISC	3,702	-	-	3,702
564	7033	TGS GAS SUPPLY	9210	9210210	A&G S&E OFFICE SUPPLIES	126	-	-	126
565	7033	TGS GAS SUPPLY	9210	9210220	A&G S&E MEMBERSHIP DUES	2,500	-	-	2,500
566	7033	TGS GAS SUPPLY	9210	9210222	A&G S&E LODGING	1,306	-	-	1,306
567	7033	TGS GAS SUPPLY	9210	9210240	A&G S&E PERMITS/FEES/ASSESSMENTS	66	-	-	66
568	7033	TGS GAS SUPPLY	9230	9230110	A&G OUTSIDE SVC MISC	18,929	-	-	18,929
569	7033	TGS GAS SUPPLY	9302	9302100	A&G MISC EXPENSES	176	-	-	176
570	7034	TGS ADMINISTRATION	8800	8800100	DISTR OTHER EXPENSES	10,629	-	-	10,629
571	7034	TGS ADMINISTRATION	8800	8800210	DISTR OTH OFFICE SUPPLIES	101	-	-	101
572	7034	TGS ADMINISTRATION	9200	9200100	A&G SALARIES	230	-	-	230
573	7034	TGS ADMINISTRATION	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	11,821	-	-	11,821
574	7034	TGS ADMINISTRATION	9210	9210221	A&G S&E TRAINING & ED	182	-	-	182
575	7034	TGS ADMINISTRATION	9210	9210100	A&G SUPPLIES & EXPENSES MISC	539	-	-	539
576	7034	TGS ADMINISTRATION	9210	9210210	A&G S&E OFFICE SUPPLIES	59	-	-	59
577	7034	TGS ADMINISTRATION	9210	9210102	A&G S&E EMPL MISC	61	-	-	61
578	7034	TGS ADMINISTRATION	9210	9210220	A&G S&E MEMBERSHIP DUES	66	-	-	66
579	7035	TGS ENGINEERING	8600	8600100	TRANS RENT	0	-	-	0
580	7035	TGS ENGINEERING	8700	8700100	DISTR GEN SUPERVISION	140,056	-	-	140,056
581	7035	TGS ENGINEERING	8800	8800100	DISTR OTHER EXPENSES	41,649	-	-	41,649
582	7035	TGS ENGINEERING	8800	8800228	DISTR OTH PERS USE AUTO	14	-	-	14
583	7035	TGS ENGINEERING	8860	8860120	DISTR MNT STRUC & IMPROV SVC BLDG	86	-	-	86

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
584	7035	TGS ENGINEERING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	57	-	-	57
585	7035	TGS ENGINEERING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	161	-	-	161
586	7035	TGS ENGINEERING	9210	9210226	A&G S&E POSTAGE	114	-	-	114
587	7035	TGS ENGINEERING	9210	9210240	A&G S&E PERMITS/FEES/ASSESSMENTS	125	-	-	125
588	7036	TGS COMMUNICATIONS	9090	9090321	INFO/INSTRUC CORP COMM DIRECT	180,503	-	-	180,503
589	7036	TGS COMMUNICATIONS	9200	9200100	A&G SALARIES	109,526	-	-	109,526
590	7036	TGS COMMUNICATIONS	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	6,838	-	-	6,838
591	7036	TGS COMMUNICATIONS	9210	9210221	A&G S&E TRAINING & ED	2,851	-	-	2,851
592	7036	TGS COMMUNICATIONS	9210	9210220	A&G S&E MEMBERSHIP DUES	98	-	-	98
593	7036	TGS COMMUNICATIONS	9210	9210201	A&G S&E ASSOC MTGS	295	-	-	295
594	7036	TGS COMMUNICATIONS	9301	9301100	A&G ADVERTISING MISC	259	-	-	259
595	7038	TGS GIS	8700	8700100	DISTR GEN SUPERVISION	64,096	-	-	64,096
596	7038	TGS GIS	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	10,249	-	-	10,249
597	7038	TGS GIS	9210	9210221	A&G S&E TRAINING & ED	475	-	-	475
598	7038	TGS GIS	9210	9210100	A&G SUPPLIES & EXPENSES MISC	570	-	-	570
599	7038	TGS GIS	9210	9210809	A&G S&E EMPLOYEE ONBOARDING PROGRAM	96	-	-	96
600	7039	TGS OUTSIDE AREAS OPERATIONS	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	9,268	-	-	9,268
601	7039	TGS OUTSIDE AREAS OPERATIONS	9210	9210210	A&G S&E OFFICE SUPPLIES	455	-	-	455
602	7039	TGS OUTSIDE AREAS OPERATIONS	9210	9210223	A&G S&E AIRFARE	29	-	-	29
603	7039	TGS OUTSIDE AREAS OPERATIONS	9260	9260307	A&G EMPL BEN EMPLOYEE EVENTS	19	-	-	19
604	7041	TGS DIVISION LEAK SURVEY	8740	8740400	DISTR MAINS & SVC LEAK SURVEY MAINS	444	-	-	444
605	7041	TGS DIVISION LEAK SURVEY	8780	8780100	DISTR MEAS & HOUSE REG MISC	315	-	-	315
606	7041	TGS DIVISION LEAK SURVEY	8800	8800100	DISTR OTHER EXPENSES	2,393	-	-	2,393
607	7042	TGS DIVISION MEASUREMENT & REGULATION	8570	8570106	TRANS MEAS & REG ST INSPEC CODE REQ	207	-	-	207
608	7042	TGS DIVISION MEASUREMENT & REGULATION	8570	8570123	TRANS MEAS & REG ST - SCADA	327	-	-	327
609	7042	TGS DIVISION MEASUREMENT & REGULATION	8700	8700100	DISTR GEN SUPERVISION	194,276	-	-	194,276
610	7042	TGS DIVISION MEASUREMENT & REGULATION	8740	8740100	DISTR MAINS & SVC MISC	1,030	-	-	1,030
611	7042	TGS DIVISION MEASUREMENT & REGULATION	8740	8740240	DISTR MAINS & SVC PERMITS/FEES/ASSESSMENTS	4,173	-	-	4,173
612	7042	TGS DIVISION MEASUREMENT & REGULATION	8740	8740207	DISTR MAINS & SVC TOOLS	145	-	-	145
613	7042	TGS DIVISION MEASUREMENT & REGULATION	8750	8750100	DISTR MEAS & REG ST MISC	37,262	-	-	37,262
614	7042	TGS DIVISION MEASUREMENT & REGULATION	8750	8750114	DISTR MEAS & REG ST ODORIZATION	39,142	-	-	39,142
615	7042	TGS DIVISION MEASUREMENT & REGULATION	8750	8750121	DISTR MEAS & REG ST MECH CHARTS	4,197	-	-	4,197
616	7042	TGS DIVISION MEASUREMENT & REGULATION	8750	8750123	DISTR MEAS & REG ST SCADA OPERATIONS	469	-	-	469
617	7042	TGS DIVISION MEASUREMENT & REGULATION	8760	8760100	DISTR IND MEAS & REG ST MISC	16,970	-	-	16,970
618	7042	TGS DIVISION MEASUREMENT & REGULATION	8760	8760117	DISTR IND ROTARY METER DIFF TEST	13,207	-	-	13,207
619	7042	TGS DIVISION MEASUREMENT & REGULATION	8760	8760112	DISTR IND MEAS & REG VOL PROC EFM	2,759	-	-	2,759
620	7042	TGS DIVISION MEASUREMENT & REGULATION	8770	8770104	DISTR C G METER INSPECTING/TESTING	1,057	-	-	1,057
621	7042	TGS DIVISION MEASUREMENT & REGULATION	8790	8790100	DISTR CUST INSTALL MISC EXP	1,775	-	-	1,775
622	7042	TGS DIVISION MEASUREMENT & REGULATION	8800	8800100	DISTR OTHER EXPENSES	515	-	-	515
623	7042	TGS DIVISION MEASUREMENT & REGULATION	8800	8800210	DISTR OTH OFFICE SUPPLIES	435	-	-	435
624	7042	TGS DIVISION MEASUREMENT & REGULATION	8870	8870100	DISTR MNT MAINS MISC	3,691	-	-	3,691
625	7042	TGS DIVISION MEASUREMENT & REGULATION	8890	8890112	DISTR MNT MEAS & REG ST - EFM	4,965	-	-	4,965
626	7042	TGS DIVISION MEASUREMENT & REGULATION	8890	8890114	DISTR MNT MEAS & REG ODORIZATION	2,028	-	-	2,028
627	7042	TGS DIVISION MEASUREMENT & REGULATION	8890	8890100	DISTR MNT MEAS & REG ST MISC	(23,543)	-	-	(23,543)
628	7042	TGS DIVISION MEASUREMENT & REGULATION	8900	8900100	DISTR MNT IND MEAS & REG ST MISC	43,718	-	-	43,718
629	7042	TGS DIVISION MEASUREMENT & REGULATION	8910	8910100	DISTR MNT C G MEAS & REG ST MISC	143	-	-	143
630	7042	TGS DIVISION MEASUREMENT & REGULATION	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	14,483	-	-	14,483
631	7042	TGS DIVISION MEASUREMENT & REGULATION	9210	9210100	A&G SUPPLIES & EXPENSES MISC	1,538	-	-	1,538
632	7042	TGS DIVISION MEASUREMENT & REGULATION	9210	9210304	A&G S&E CELLULAR PHONES	38	-	-	38
633	7042	TGS DIVISION MEASUREMENT & REGULATION	9210	9210201	A&G S&E ASSOC MTGS	2,935	-	-	2,935
634	7043	TGS DIVISION CORROSION/CATHODIC PROTECTION	8630	8630101	TRANS MNT MAINS CATH PROTECTION	301	-	-	301
635	7043	TGS DIVISION CORROSION/CATHODIC PROTECTION	8790	8790100	DISTR CUST INSTALL MISC EXP	-	-	-	-
636	7043	TGS DIVISION CORROSION/CATHODIC PROTECTION	8800	8800100	DISTR OTHER EXPENSES	50	-	-	50

WKP G.a.2.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
637	7043	TGS DIVISION CORROSION/CATHODIC PROTECTION	8800	8800210	DISTR OTH OFFICE SUPPLIES	-	-	-	-
638	7043	TGS DIVISION CORROSION/CATHODIC PROTECTION	8870	8870101	DISTR MNT MAINS CATHODIC PROTECT	156,060	-	-	156,060
639	7043	TGS DIVISION CORROSION/CATHODIC PROTECTION	8870	8870100	DISTR MNT MAINS MISC	348	-	-	348
640	7043	TGS DIVISION CORROSION/CATHODIC PROTECTION	8870	8870130	DISTR MNT MAINS 3RD PARTY DAM TEAROUT	-	-	-	-
641	7043	TGS DIVISION CORROSION/CATHODIC PROTECTION	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	293	-	-	293
642	7044	TGS TRANSMISSION	8530	8530100	TRANS COMPR ST MISC	2,527	-	-	2,527
643	7044	TGS TRANSMISSION	8560	8560228	TRANS MAINS PERSONAL USE OF AUTO	39	-	-	39
644	7044	TGS TRANSMISSION	8560	8560402	TRANS MAINS CODE LEAK SURVEY	263	-	-	263
645	7044	TGS TRANSMISSION	8570	8570106	TRANS MEAS & REG ST INSPEC CODE REQ	161	-	-	161
646	7044	TGS TRANSMISSION	8590	8590100	TRANS OTH MISC EXP	164	-	-	164
647	7044	TGS TRANSMISSION	8630	8630250	TRANS MNT MAINS PIPELINE INTEGRITY MANAGEMENT	32	-	-	32
648	7044	TGS TRANSMISSION	8630	8630115	TRANS MNT MAINS REPAIRS FR LEAKAGE	1,392	-	-	1,392
649	7044	TGS TRANSMISSION	8630	8630150	TRANS MNT REGULATORY COMPLIANCE MRC	1,800	-	-	1,800
650	7044	TGS TRANSMISSION	8650	8650100	TRANS MNT MEAS & REG ST EQUIP	1,659	-	-	1,659
651	7044	TGS TRANSMISSION	8740	8740100	DISTR MAINS & SVC MISC	159	-	-	159
652	7044	TGS TRANSMISSION	8770	8770104	DISTR C G METER INSPECTING/TESTING	1,118	-	-	1,118
653	7044	TGS TRANSMISSION	8780	8780100	DISTR MEAS & HOUSE REG MISC	63	-	-	63
654	7044	TGS TRANSMISSION	8800	8800100	DISTR OTHER EXPENSES	6,195	-	-	6,195
655	7044	TGS TRANSMISSION	8800	8800400	DISTR OTH SAFETY	4,692	-	-	4,692
656	7044	TGS TRANSMISSION	8800	8800210	DISTR OTH OFFICE SUPPLIES	29	-	-	29
657	7044	TGS TRANSMISSION	8870	8870100	DISTR MNT MAINS MISC	2,754	-	-	2,754
658	7044	TGS TRANSMISSION	8870	8870120	DISTR MNT MAINS LEAK REPAIR	652	-	-	652
659	7044	TGS TRANSMISSION	9020	9020100	METER READING MISC EXP	2,342	-	-	2,342
660	7044	TGS TRANSMISSION	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	122	-	-	122
661	7044	TGS TRANSMISSION	9210	9210100	A&G SUPPLIES & EXPENSES MISC	432	-	-	432
662	7044	TGS TRANSMISSION	9210	9210102	A&G S&E EMPL MISC	85	-	-	85
663	7044	TGS TRANSMISSION	9210	9210226	A&G S&E POSTAGE	109	-	-	109
664	7044	TGS TRANSMISSION	9302	9302100	A&G MISC EXPENSES	119	-	-	119
665	7044	TGS TRANSMISSION	9302	9302120	A&G MISC EMPL MOVING	11,404	-	-	11,404
666	7045	TGS DIVISION LINE LOCATING	8780	8780100	DISTR MEAS & HOUSE REG MISC	54	-	-	54
667	7045	TGS DIVISION LINE LOCATING	8800	8800100	DISTR OTHER EXPENSES	34	-	-	34
668	7045	TGS DIVISION LINE LOCATING	9200	9200100	A&G SALARIES	149,777	-	-	149,777
669	7045	TGS DIVISION LINE LOCATING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	(1,073)	-	-	(1,073)
670	7045	TGS DIVISION LINE LOCATING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	4,592	-	-	4,592
671	7045	TGS DIVISION LINE LOCATING	9210	9210304	A&G S&E CELLULAR PHONES	11	-	-	11
672	7046	TGS CUST SVC QUALITY ASSURANCE	9050	9050100	CUST ACCTS MISC EXP	-	-	-	-
673	7047	TGS CUST SVC TRAINING	9050	9050100	CUST ACCTS MISC EXP	-	-	-	-
674	7048	TGS VIRTUAL CALL CTR	9030	9030100	CUST REC/COLLEC EXP MISC	-	-	-	-
675	7049	TGS CASH PROCESSING	9010	9010100	CUST ACCTG/COLL SUPERVISION	3	-	-	3
676	7049	TGS CASH PROCESSING	9030	9030100	CUST REC/COLLEC EXP MISC	681	-	-	681
677	7049	TGS CASH PROCESSING	9030	9030110	CUST RECORDS EXPENSE	483,217	-	-	483,217
678	7049	TGS CASH PROCESSING	9030	9030226	CUST REC/COLLEC POSTAGE	697	-	-	697
679	7049	TGS CASH PROCESSING	9030	9030125	CUST REC/COLLEC LOCKBOX	243,615	-	-	243,615
680	7049	TGS CASH PROCESSING	9210	9210210	A&G S&E OFFICE SUPPLIES	110	-	-	110
681	7050	TGS CUSTOMER SVC ADMIN	9010	9010100	CUST ACCTG/COLL SUPERVISION	215,934	-	-	215,934
682	7050	TGS CUSTOMER SVC ADMIN	9030	9030100	CUST REC/COLLEC EXP MISC	2,809	-	-	2,809
683	7050	TGS CUSTOMER SVC ADMIN	9030	9030110	CUST RECORDS EXPENSE	2,137	-	-	2,137
684	7050	TGS CUSTOMER SVC ADMIN	9030	9030228	CUST REC/COLLEC EXP PERS USE AUTO	107	-	-	107
685	7050	TGS CUSTOMER SVC ADMIN	9050	9050100	CUST ACCTS MISC EXP	1	-	-	1
686	7050	TGS CUSTOMER SVC ADMIN	9050	9050120	CUST ACCTS SVC BLDG	20	-	-	20
687	7050	TGS CUSTOMER SVC ADMIN	9050	9050228	CUST ACCTS PERS USE AUTO	26	-	-	26
688	7050	TGS CUSTOMER SVC ADMIN	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	(0)	-	-	(0)
689	7050	TGS CUSTOMER SVC ADMIN	9210	9210100	A&G SUPPLIES & EXPENSES MISC	1,019	-	-	1,019

WKP G.a.2.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
690	7050	TGS CUSTOMER SVC ADMIN	9210	9210301	A&G S&E TELE LONG DISTANCE	53	-	-	53
691	7050	TGS CUSTOMER SVC ADMIN	9210	9210303	A&G S&E TELE LOCAL LINES	26,672	-	-	26,672
692	7050	TGS CUSTOMER SVC ADMIN	9210	9210304	A&G S&E CELLULAR PHONES	7,745	-	-	7,745
693	7050	TGS CUSTOMER SVC ADMIN	9210	9210308	A&G S&E TELE DATA	21,761	-	-	21,761
694	7050	TGS CUSTOMER SVC ADMIN	9210	9210220	A&G S&E MEMBERSHIP DUES	85	-	-	85
695	7050	TGS CUSTOMER SVC ADMIN	9310	9310120	A&G RENTS EQUIPMENT	16,357	-	-	16,357
696	7050	TGS CUSTOMER SVC ADMIN	9310	9310100	A&G RENTS LAND/FACILITY	282,649	-	-	282,649
697	7050	TGS CUSTOMER SVC ADMIN	9320	9320140	A&G MNT AGREEMENT FEES	4,158	-	-	4,158
698	7051	TGS WEB WORK	9030	9030100	CUST REC/COLLEC EXP MISC	(6,360)	-	-	(6,360)
699	7051	TGS WEB WORK	9030	9030110	CUST RECORDS EXPENSE	129,804	-	-	129,804
700	7055	TGS FLEET	8700	8700100	DISTR GEN SUPERVISION	185	-	-	185
701	7055	TGS FLEET	8740	8740100	DISTR MAINS & SVC MISC	139	-	-	139
702	7055	TGS FLEET	8780	8780100	DISTR MEAS & HOUSE REG MISC	-	-	-	-
703	7055	TGS FLEET	8800	8800100	DISTR OTHER EXPENSES	233	-	-	233
704	7055	TGS FLEET	8800	8800400	DISTR OTH SAFETY	227	-	-	227
705	7055	TGS FLEET	8870	8870101	DISTR MNT MAINS CATHODIC PROTECT	38	-	-	38
706	7055	TGS FLEET	8890	8890100	DISTR MNT MEAS & REG ST MISC	785	-	-	785
707	7055	TGS FLEET	8900	8900100	DISTR MNT IND MEAS & REG ST MISC	492	-	-	492

WKP G.a.2.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
708	7055	TGS FLEET	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	25	-	-	25
709	7055	TGS FLEET	9210	9210102	A&G S&E EMPL MISC	1,236	-	-	1,236
710	7056	TGS MARKET PLANNING	9020	9020100	METER READING MISC EXP	(3,400)	-	-	(3,400)
711	7056	TGS MARKET PLANNING	9080	9080100	CUST ASST MISC EXP	107,021	-	-	107,021
712	7056	TGS MARKET PLANNING	9090	9090100	INFO/INSTRUC MISC	20,390	-	-	20,390
713	7056	TGS MARKET PLANNING	9210	9210210	A&G S&E OFFICE SUPPLIES	58	-	-	58
714	7056	TGS MARKET PLANNING	9210	9210226	A&G S&E POSTAGE	11	-	-	11
715	7056	TGS KEY ACCOUNTS	9080	9080100	CUST ASST MISC EXP	124,192	-	-	124,192
716	7056	TGS KEY ACCOUNTS	9130	9130100	ADVERTISING MISC EXP	3,692	-	-	3,692
717	7056	TGS KEY ACCOUNTS	9210	9210221	A&G S&E TRAINING & ED	394	-	-	394
718	7056	TGS KEY ACCOUNTS	9210	9210100	A&G SUPPLIES & EXPENSES MISC	117	-	-	117
719	7056	TGS KEY ACCOUNTS	9210	9210201	A&G S&E ASSOC MTGS	236	-	-	236
720	7057	TGS DISPATCH	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	(82)	-	-	(82)
721	7058	TGS OPNS BUDGETS AND FORECASTS	9200	9200100	A&G SALARIES	79,966	-	-	79,966
722	7058	TGS OPNS BUDGETS AND FORECASTS	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	2,605	-	-	2,605
723	7058	TGS OPNS BUDGETS AND FORECASTS	9210	9210100	A&G SUPPLIES & EXPENSES MISC	38	-	-	38
724	7058	TGS OPNS BUDGETS AND FORECASTS	9210	9210210	A&G S&E OFFICE SUPPLIES	54	-	-	54
725	7058	TGS OPNS BUDGETS AND FORECASTS	9210	9210304	A&G S&E CELLULAR PHONES	20	-	-	20
726	7058	TGS OPERATIONS FINANCIAL PLANNING	9200	9200100	A&G SALARIES	83,408	-	-	83,408
727	7058	TGS OPERATIONS FINANCIAL PLANNING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	934	-	-	934
728	7058	TGS OPERATIONS FINANCIAL PLANNING	9210	9210221	A&G S&E TRAINING & ED	341	-	-	341
729	7058	TGS OPERATIONS FINANCIAL PLANNING	9210	9210100	A&G SUPPLIES & EXPENSES MISC	124	-	-	124
730	7058	TGS OPERATIONS FINANCIAL PLANNING	9210	9210102	A&G S&E EMPL MISC	23	-	-	23
731	7058	TGS OPERATIONS FINANCIAL PLANNING	9210	9210220	A&G S&E MEMBERSHIP DUES	66	-	-	66
732	7059	TGS PROJECT COORDINATION	8800	8800100	DISTR OTHER EXPENSES	66,604	-	-	66,604
733	7059	TGS PROJECT COORDINATION	8800	8800400	DISTR OTH SAFETY	66	-	-	66
734	7059	TGS PROJECT COORDINATION	8800	8800210	DISTR OTH OFFICE SUPPLIES	140	-	-	140
735	7059	TGS PROJECT COORDINATION	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	8,510	-	-	8,510
736	7059	TGS PROJECT COORDINATION	9210	9210100	A&G SUPPLIES & EXPENSES MISC	52	-	-	52
737	7060	TGS WORK SCHEDULING MANAGEMENT	8800	8800100	DISTR OTHER EXPENSES	52,546	-	-	52,546
738	7060	TGS WORK SCHEDULING MANAGEMENT	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	11,088	-	-	11,088
739	7060	TGS WORK SCHEDULING MANAGEMENT	9210	9210220	A&G S&E MEMBERSHIP DUES	40	-	-	40
740	7061	TGS PROJECT CLOSURE	8740	8740225	DISTR MAINS & SVC UNIFORMS	146	-	-	146
741	7061	TGS PROJECT CLOSURE	8780	8780100	DISTR MEAS & HOUSE REG MISC	66	-	-	66
742	7061	TGS PROJECT CLOSURE	8800	8800100	DISTR OTHER EXPENSES	7,416	-	-	7,416
743	7061	TGS PROJECT CLOSURE	8800	8800400	DISTR OTH SAFETY	18	-	-	18
744	7061	TGS PROJECT CLOSURE	8800	8800210	DISTR OTH OFFICE SUPPLIES	27	-	-	27
745	7061	TGS PROJECT CLOSURE	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	6,729	-	-	6,729
746	7061	TGS PROJECT CLOSURE	9210	9210100	A&G SUPPLIES & EXPENSES MISC	130	-	-	130
747	7061	TGS PROJECT CLOSURE	9210	9210210	A&G S&E OFFICE SUPPLIES	183	-	-	183
748	7061	TGS PROJECT CLOSURE	9302	9302100	A&G MISC EXPENSES	227	-	-	227
749	7062	TGS MARKET DEVELOPMENT	9080	9080100	CUST ASST MISC EXP	342	-	-	342
750	7088	TGS MATERIAL MGMT	9210	9210226	A&G S&E POSTAGE	248	-	-	248
751	7090	TGS INDUSTRIAL BILLING	9030	9030100	CUST REC/COLLEC EXP MISC	115,707	-	-	115,707
752	7090	TGS TRANSPORT SERVICES	9030	9030100	CUST REC/COLLEC EXP MISC	120,580	-	-	120,580
753	7091	TGS CUSTOMER DEVELOPMENT	4261	4261212	CIVIC EXPENSES - BUSINESS & COMMERCIAL DEVEL	-	-	-	-
754	7091	TGS CUSTOMER DEVELOPMENT	8800	8800400	DISTR OTH SAFETY	283	-	-	283
755	7091	TGS CUSTOMER DEVELOPMENT	9080	9080100	CUST ASST MISC EXP	43,512	-	-	43,512
756	7091	TGS CUSTOMER DEVELOPMENT	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	267	-	-	267
757	7091	TGS CUSTOMER DEVELOPMENT	9210	9210100	A&G SUPPLIES & EXPENSES MISC	658	-	-	658
758	7091	TGS CUSTOMER DEVELOPMENT	9210	9210210	A&G S&E OFFICE SUPPLIES	788	-	-	788
759	7091	TGS CUSTOMER DEVELOPMENT	9210	9210102	A&G S&E EMPL MISC	124	-	-	124
760	7091	TGS CUSTOMER DEVELOPMENT	9210	9210220	A&G S&E MEMBERSHIP DUES	100	-	-	100

WKP G.a.2.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
761	7091	TGS COMMERCIAL PROJECT MANAGEMENT	4261	4261212	CIVIC EXPENSES - BUSINESS & COMMERCIAL DEVEL	-	-	-	-
762	7091	TGS COMMERCIAL PROJECT MANAGEMENT	8800	8800400	DISTR OTH SAFETY	13	-	-	13
763	7091	TGS COMMERCIAL PROJECT MANAGEMENT	9080	9080100	CUST ASST MISC EXP	57,736	-	-	57,736
764	7091	TGS COMMERCIAL PROJECT MANAGEMENT	9080	9080228	CUST ASST PERS USE AUTO	124	-	-	124
765	7091	TGS COMMERCIAL PROJECT MANAGEMENT	9080	9080125	CUST ASST COMM TRADESHOW/EXHIBIT	(5,600)	-	-	(5,600)
766	7091	TGS COMMERCIAL PROJECT MANAGEMENT	9130	9130100	ADVERTISING MISC EXP	847	-	-	847
767	7091	TGS COMMERCIAL PROJECT MANAGEMENT	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	366	-	-	366
768	7091	TGS COMMERCIAL PROJECT MANAGEMENT	9210	9210100	A&G SUPPLIES & EXPENSES MISC	183	-	-	183
769	7091	TGS COMMERCIAL PROJECT MANAGEMENT	9210	9210210	A&G S&E OFFICE SUPPLIES	424	-	-	424
770	7091	TGS COMMERCIAL PROJECT MANAGEMENT	9210	9210220	A&G S&E MEMBERSHIP DUES	3,009	-	-	3,009
771	7091	TGS COMMERCIAL PROJECT MANAGEMENT	9210	9210404	A&G S&E MAIL ROOM	25	-	-	25
772	7092	TGS BUILDER HOTLINE	9050	9050100	CUST ACCTS MISC EXP	49	-	-	49
773	7092	TGS BUILDER HOTLINE	9080	9080100	CUST ASST MISC EXP	3,644	-	-	3,644
774	7092	TGS BUILDER HOTLINE	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	4,282	-	-	4,282
775	7092	TGS BUILDER HOTLINE	9210	9210201	A&G S&E ASSOC MTGS	1,198	-	-	1,198
776	7092	TGS BUILDER SERVICES	9080	9080100	CUST ASST MISC EXP	7,725	-	-	7,725
777	7092	TGS BUILDER SERVICES	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	3,295	-	-	3,295
778	7092	TGS BUILDER SERVICES	9210	9210100	A&G SUPPLIES & EXPENSES MISC	246	-	-	246
779	7092	TGS BUILDER SERVICES	9302	9302105	A&G MISC INDUSTRY DUES	608	-	-	608
780	7093	TGS BUSINESS DEV GROWTH	9080	9080100	CUST ASST MISC EXP	64,521	-	-	64,521
781	7093	TGS BUSINESS DEV GROWTH	9302	9302105	A&G MISC INDUSTRY DUES	3,000	-	-	3,000
782	7200	TGS CT GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES	-	-	-	-
783	7200	TGS CT GENERAL	9210	9210304	A&G S&E CELLULAR PHONES	-	-	-	-
784	7200	TGS CT GENERAL	9210	9210308	A&G S&E TELE DATA	-	-	-	-
785	7300	TGS ST GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES	-	-	-	-
786	7300	TGS ST GENERAL	9210	9210304	A&G S&E CELLULAR PHONES	-	-	-	-
787	7300	TGS ST GENERAL	9210	9210308	A&G S&E TELE DATA	-	-	-	-
788	7450	TGS ST GALVESTON GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES	-	-	-	-
789	7450	TGS ST GALVESTON GENERAL	9210	9210304	A&G S&E CELLULAR PHONES	-	-	-	-
790	7450	TGS ST GALVESTON GENERAL	9210	9210308	A&G S&E TELE DATA	-	-	-	-
791	7550	TGS ST PORT ARTHUR GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES	-	-	-	-
792	7550	TGS ST PORT ARTHUR GENERAL	9210	9210304	A&G S&E CELLULAR PHONES	-	-	-	-
793	7550	TGS ST PORT ARTHUR GENERAL	9210	9210308	A&G S&E TELE DATA	-	-	-	-
794	7608	TGS WT DELL CITY	9210	9210303	A&G S&E TELE LOCAL LINES	-	-	-	-
795	7608	TGS WT DELL CITY	9210	9210304	A&G S&E CELLULAR PHONES	-	-	-	-
796	7608	TGS WT DELL CITY	9210	9210308	A&G S&E TELE DATA	-	-	-	-
797	7635	TGS WT PERMIAN AREA GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES	-	-	-	-
798	7635	TGS WT PERMIAN AREA GENERAL	9210	9210304	A&G S&E CELLULAR PHONES	-	-	-	-
799	7635	TGS WT PERMIAN AREA GENERAL	9210	9210308	A&G S&E TELE DATA	-	-	-	-
800	7650	TGS WT EL PASO GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES	-	-	-	-
801	7650	TGS WT EL PASO GENERAL	9210	9210304	A&G S&E CELLULAR PHONES	-	-	-	-
802	7700	TGS RGV GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES	-	-	-	-
803	7700	TGS RGV GENERAL	9210	9210304	A&G S&E CELLULAR PHONES	-	-	-	-
804	7700	TGS RGV GENERAL	9210	9210308	A&G S&E TELE DATA	-	-	-	-
805	7800	TGS NT GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES	-	-	-	-
806	7800	TGS NT GENERAL	9210	9210304	A&G S&E CELLULAR PHONES	-	-	-	-
807	7800	TGS NT GENERAL	9210	9210308	A&G S&E TELE DATA	-	-	-	-
808	7801	TGS NT DISTRICT ADMIN	9210	9210303	A&G S&E TELE LOCAL LINES	-	-	-	-
809	7801	TGS NT DISTRICT ADMIN	9210	9210304	A&G S&E CELLULAR PHONES	-	-	-	-
810	7801	TGS NT DISTRICT ADMIN	9210	9210308	A&G S&E TELE DATA	-	-	-	-
811	7860	TGS BORGER GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES	-	-	-	-
812	7860	TGS BORGER GENERAL	9210	9210304	A&G S&E CELLULAR PHONES	-	-	-	-
813	7860	TGS BORGER GENERAL	9210	9210308	A&G S&E TELE DATA	-	-	-	-

WKP G.a.2.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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.	TO COST CENTER	TO COST CENTER DESCRIPTION	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
						(a)	(b)	(c)	(d)
814						**41,474,005**	**7,348,273**	**29,104,981**	**77,927,259**
815									
816									
817						**Calculation of O&M Expense Factor**			
818									
819						Per Book Shared Services (net of the A&G transfer credit)			$77,927,259
820						Less: depreciation expense that does not get an O&M factor			(5,050,231)
821						Less: tax expense accounts			(3,681,820)
822						**Total O&M Shared Service Expenses**			**$69,195,207**
823									
824									
825									
826						Total O&M Shared Service Expenses			$69,195,207
827						Add back Account 9220902 A&G Transfer Credit/Construction Overhead			8,822,879
828						**Grand Total Shared Service Expenses:**			**$78,018,086**
829									
830						**O&M effective expense factor**			**88.69%**
831						Capitalization factor			11.31%
832									100.00%

Source: WKP G.a.2.a1 Shared Service per book including Distrigas (CONFIDENTIAL) - CGSA.xlsx
Source: WKP G.a.2.a2 Corporate Costs Allocated on a Causal Basis and Through Distrigas-(CONFIDENTIAL) - CGSA.xlsx

SCHEDULE G-1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

REMOVE GAS REVENUE AND COST OF GAS

LINE NO.	DESCRIPTION	AMOUNT
		(a)
1	Remove Cost of Gas Revenue Collected through Cost of Gas Clause	$75,042,680
2	Remove Test Year Cost of Gas Expense	(75,042,680)
3	Net Adjustment	$0

Source: SCH G-2 and SCH G-3 Revenue Recon.xlsx

SCHEDULE G-2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

NORMALIZE GAS SALES REVENUE

LINE NO.	DESCRIPTION	TOTAL # OF BILLS	CCF	REVENUE	
		(a)	(b)	(c)	
	OPERATING GAS SALES REVENUE:				
1	Test Year Gas Sales Revenue per Book - Accts 4800 thru 4820 (note this does not include franchise or gross receipt taxes)	3,683,691	162,697,883	$166,636,721	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx and SCH G-2 and SCH G-3 Billing Determinants By Class.xlsx
2	Less: Test Year Gas Costs collected through Cost of Gas Clause			(75,042,680)	
3	Base Sales Revenue as Recorded	3,683,691	162,697,883	$91,594,041	
	Adjustments:				
4	Remove Test Year WNA Collections			$376,216	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx
5	Weather Normalization Adjustment		(7,633,363)	(745,492)	Source: SCH G-2 and SCH G-3 Weather Adjustment_10 Norm.xlsx
6	Customers Switching between Gas Sales and Transport	61	11,730	4,688	Source: SCH G-2 and SCH G-3 Switching, New Customer, and Termination Adjustment.xlsx
7	Customer Growth (Loss) Adjustment	19,175	319,297	369,076	Source: SCH G-2 Growth Adjustment.xlsx
8	Post Growth (Loss) Adjustment thru September 2019	4,833	85,087	92,591	Source: SCH G-2 Post Test Year Growth.xlsx
9	Annualize to Current Rates - GRIP			5,080,306	Source: SCH G-2 and SCH G-3 GRIP Annualization.xlsx
10	Annualize to Current Rates - COSA			138,315	Source: SCH G-2 and SCH G-3 COSA Annualization.xlsx
11	Adjustment for Unmetered Service			2,655	Source: SCH G-2 Unmetered Service Adjustment.xlsx
12	Total Adjustments	24,068.86	(7,217,250)	$5,318,354	
13	Base Revenue As Adjusted	3,707,760	155,480,633	$96,912,395	

Calculation of Normalized Gas Sales Revenue used for Advertising Limitation Calculation:

LINE NO.	DESCRIPTION		
14	Calculation of Normalized Cost of Gas Revenue		
15	Normalized CCF		155,480,633
16	Test Year Cost of Gas Revenue	$75,042,680	
17	Test Year CCF	162,697,883	
18	Effective Rate	0.4612	0.4612
19	Normalized Cost of Gas Revenue		$71,713,800

SCHEDULE G-3

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

NORMALIZE OTHER UTILITY REVENUE

LINE NO.	DESCRIPTION	REVENUE (a)	
1	Test Year Transportation Revenue - Acct 4893	$9,318,914	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx
2	Remove Estimated Revenue Journal Entries	$1,652	Source: SCH G-2 and SCH G-3 Revenue Recon.xlsx
3	Adjustment to Normalize Weather	(79,118)	Source: SCH G-2 and SCH G-3 Weather Adjustment_10 Norm.xlsx
4	Customers Switching between Gas Sales and Transport	(6,650)	Source: SCH G-2 and SCH G-3 Switching, New Customer, and Termination Adjustment.xlsx
5	Customers Switching between Special Contract and Standard Transport	323,289	Source: SCH G-3 Special Contract Transport Switching Adjustment.xlsx
6	New Customer	4,062	Source: SCH G-2 and SCH G-3 Switching, New Customer, and Termination Adjustment.xlsx
7	Customer Terminated	(14,342)	Source: SCH G-2 and SCH G-3 Switching, New Customer, and Termination Adjustment.xlsx
8	Annualize to Current Rates - GRIP	127,541	Source: SCH G-2 and SCH G-3 COSA Annualization.xlsx
9	Annualize to Current Rates - COSA	1,441	Source: SCH G-2 and SCH G-3 GRIP Annualization.xlsx
10	Total Adjustments	$357,875	
11	Total Transportation Revenue As Adjusted	$9,676,789	
12	Test Year Service Fees - Acct 4880	$2,137,994	Source: SCH G-2 and SCH G-3 Revenue Recon.xlsx
13	Adjustment for Change in Service Fees	277,029	Source: SCH G-3 Service Fee Adjustment.xlsx
14	Total Service Fee Revenue As Adjusted	$2,415,023	
15	Test Year Other Utility Revenue - Acct 4950	$409,496	Source: SCH G-2 and SCH G-3 Revenue Recon.xlsx
16	Remove Interest on Storage Gas	(347,618)	Source: SCH G-2 and SCH G-3 Revenue Recon.xlsx
17	Remove Hurricane Harvey Insurance Reimbursement	(61,878)	Source: SCH G-2 and SCH G-3 Revenue Recon.xlsx
18	Total Other Utility Revenue As Adjusted	$0	
19	Total Transportation, Service Fees, and Other Utility Revenue As Adjusted	$12,091,812	

SCHEDULE G-4

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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 June 2019	WKP G-4.c	$858,315	$416,986	$481,045	
2	Salary Base Payroll for June 2019	WKP G-4.c	350,513	927,569	4,113,004	
3	Total Base Payroll for June 2019		$1,208,827	$1,344,555	$4,594,049	
4	Annualized Hourly Base Payroll		$11,158,091	$5,420,822	$6,253,579	
5	Annualized Salary Base Payroll		4,206,152	11,130,823	49,356,048	
6	Total Proforma Base Payroll		$15,364,243	$16,551,645	$55,609,627	
7	December Merit Increase Percent		3.864%	3.864%	3.169%	
8	Adjustment to include December Merit Increases		593,736	639,622	1,762,148	
9	Total Proforma Base Payroll		$15,957,979	$17,191,267	$57,371,774	
10	Total Test Year Base Payroll	WKP G-4.b	15,153,564	14,844,492	51,899,060	
11	Total Allocable Base Payroll Adjustment (Ln 9 minus Ln 10)		$804,414	$2,346,774	$5,472,714	
12	Allocation to TGS		100%	100%	25.01%	
13	Allocated Base Payroll Adjustment to TGS (Ln 11 times Ln 12)		$804,414	$2,346,774	$1,368,726	
14	Allocation to Service Area	WKP A.b	100%	46.49%	46.49%	
15	Allocated Base Payroll Adjustment to Service Area (Ln 13 times Ln 14)		$804,414	$1,091,088	$636,363	
16	Payroll Expense Factor	WKP G-4.b	53%	76%	83%	
17	Test Year Base Payroll O&M Expense Adjustment (Ln 15 times Ln 16)		$425,053.77	$826,629	$525,727	
18	Adjustment Summary:					
19	Account 9302		$0	$0	$525,727	$525,727
20	Other O&M Accounts (See WKP G-4.a for Distribution by FERC Account)		425,054	826,629	0	1,251,682
21	Total		$425,054	$826,629	$525,727	$1,777,410
22	Total Test Year Base Payroll Expense after Allocation		$8,007,169	$5,228,829	$4,985,600	$18,221,598
23	Total as Adjusted Base Payroll Expense after Allocation		8,432,223	6,055,458	5,511,327	19,999,008

WKP G-4.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	2,064	0.02%	149
3	8560	152,177	1.65%	7,021	8560	86,589	0.75%	6,233
4	8570	0	0.00%	0	8570	336	0.00%	24
5	8590	0	0.00%	0	8590	0	0.00%	0
6	8610	0	0.00%	0	8610	0	0.00%	0
7	8630	231	0.00%	11	8630	1,530	0.01%	110
8	8650	0	0.00%	0	8650	1,463	0.01%	105
9	8700	275,452	2.99%	12,708	8700	382,939	3.33%	27,566
10	8710	0	0.00%	0	8710	473,818	4.13%	34,107
11	8740	859,379	9.33%	39,648	8740	25,661	0.22%	1,847
12	8750	178,934	1.94%	8,255	8750	68,771	0.60%	4,950
13	8760	22,254	0.24%	1,027	8760	74,921	0.65%	5,393
14	8770	0	0.00%	0	8770	6,442	0.06%	464
15	8780	2,965,328	32.19%	136,807	8780	0	0.00%	0
16	8790	85,878	0.93%	3,962	8790	9	0.00%	1
17	8800	482,409	5.24%	22,256	8800	136,066	1.18%	9,795
18	8850	0	0.00%	0	8850	0	0.00%	0
19	8860	0	0.00%	0	8860	0	0.00%	0
20	8870	1,648,914	17.90%	76,073	8870	142,034	1.24%	10,224
21	8890	269,277	2.92%	12,423	8890	6,869	0.06%	494
22	8900	416,013	4.52%	19,193	8900	47,013	0.41%	3,384
23	8910	16,192	0.18%	747	8910	115	0.00%	8
24	8920	446,706	4.85%	20,609	8920	0	0.00%	0
25	8930	6,477	0.07%	299	8930	0	0.00%	0
26	9010	0	0.00%	0	9010	244,355	2.13%	17,590
27	9020	479,768	5.21%	22,134	9020	0	0.00%	0
28	9030	151,650	1.65%	6,996	9030	3,724,915	32.44%	268,135
29	9050	12,544	0.14%	579	9050	0	0.00%	0
30	9080	459,647	4.99%	21,206	9080	297,231	2.59%	21,396
31	9120	0	0.00%	0	9120	0	0.00%	0
32	9130	0	0.00%	0	9130	0	0.00%	0
33	9200	283,949	3.08%	13,100	9200	5,759,412	50.15%	414,587
34	9210	0	0.00%	0	9210	1	0.00%	0
35	9260	0	0.00%	0	9260	0	0.00%	0
36	9280	0	0.00%	0	9302	910	0.01%	66
37	9302	0	0.00%	0	9302	0	0.00%	0
38	9320	0	0.00%	0	9320	0	0.00%	0
39	Total	$9,213,179	100.00%	$425,054	Total	$11,483,465	100.00%	$826,629

WKP G-4.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$9,334	$0	$0	$0	$0	$0	$9,334	$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	205,005	68	0	63,531	0	20,224	172,125	68	0	63,531	0	20,224	$32,880	0	0	0	0	0
4	1840	5,183,903	1,334,649	737,884	2,486,692	2,339,135	8,291,445	4,288,279	1,217,416	710,374	2,483,716	2,338,729	8,291,431	$895,624	117,233	27,509	2,976	406	15
5	1860	0	0	0	0	0	0	0	0	0	0	0	0	$0	0	0	0	0	0
6	2530	73,174	0	0	210,453	0	0	72,542	0	0	210,453	0	0	$633	0	0	0	0	0
7	Total Capital	$5,462,082	$1,334,718	$737,884	$2,760,676	$2,339,135	$8,321,003	$4,532,946	$1,217,484	$710,374	$2,757,700	$2,338,729	$8,320,988	$929,136	$117,233	$27,509	$2,976	$406	$15
	Expense																		
8	8500	$0	$0	$0	$0	$0	$79,509	$0	$0	$0	$0	$0	$79,509	$0	$0	$0	$0	$0	$0
9	8530	0	2,064	0	0	0	0	0	1,311	0	0	0	0	0	752	0	0	0	0
10	8560	144,934	232	147,158	7,244	86,357	166,527	130,146	232	147,156	7,244	86,357	166,527	14,788	0	2	0	0	0
11	8570	0	336	0	0	0	0	0	286	0	0	0	0	0	50	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	33,213	0	0	0	0	0	33,213	0	0	0	0	0	0
14	8630	231	1,530	0	0	0	0	231	1,136	0	0	0	0	0	393	0	0	0	0
15	8650	0	1,463	0	0	0	0	0	1,463	0	0	0	0	0	0	0	0	0	0
16	8700	15,771	76,202	66,764	259,681	306,737	1,210,979	15,425	75,369	61,639	259,681	306,737	1,210,979	347	834	5,125	0	0	0
17	8710	0	398,787	0	0	75,031	0	0	300,442	0	0	74,026	0	0	98,345	0	0	1,005	0
18	8740	556,567	988	56,868	302,812	24,673	113,728	490,076	961	56,050	302,374	24,673	113,728	66,491	27	819	438	0	0
19	8750	97,850	68,742	0	81,084	28	0	91,983	67,325	0	80,802	28	0	5,867	1,417	0	282	0	0
20	8760	16,481	49,510	0	5,773	25,411	0	15,493	48,036	0	5,490	25,411	0	988	1,475	0	282	0	0
21	8770	0	2,980	0	0	3,462	0	0	2,978	0	0	3,462	0	0	2	0	0	0	0
22	8780	2,657,351	0	110,227	307,977	0	59,676	2,031,277	0	106,094	307,977	0	59,676	626,074	0	4,133	0	0	0
23	8790	77,115	9	0	8,764	0	0	59,869	0	0	8,764	0	0	17,245	9	0	0	0	0
24	8800	329,843	1,568	103,565	152,567	134,499	0	307,956	1,557	103,565	152,553	134,499	0	21,887	11	0	14	0	0
25	8850	0	0	0	0	0	154,797	0	0	0	0	0	154,797	0	0	0	0	0	0
26	8860	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	8870	1,471,256	142,034	0	177,658	0	0	1,144,836	136,350	0	175,852	0	0	326,421	5,685	0	1,806	0	0
28	8890	216,662	6,869	0	52,616	0	0	192,738	6,837	0	52,051	0	0	23,923	32	0	565	0	0
29	8900	361,773	46,641	0	54,241	372	0	322,400	45,386	0	53,676	218	0	39,373	1,255	0	565	154	0
30	8910	12,942	115	0	3,250	0	0	10,112	115	0	3,250	0	0	2,829	0	0	0	0	0
31	8920	400,437	0	0	46,269	0	0	261,536	0	0	45,934	0	0	138,901	0	0	335	0	0
32	8930	6,476	0	0	1	0	0	6,354	0	0	0	0	0	122	0	0	1	0	0
33	9010	0	39,954	0	0	204,401	2,387	0	39,625	0	0	204,401	2,387	0	329	0	0	0	0
34	9020	404,562	0	0	75,206	0	0	393,275	0	0	75,206	0	0	11,287	0	0	0	0	0
35	9030	129,958	2,775,449	0	21,691	949,466	0	105,687	2,727,151	0	21,691	949,253	0	24,272	48,297	0	0	213	0
36	9050	1,399	0	606,126	11,145	0	1,490,189	1,393	0	596,208	11,145	0	1,490,189	6	0	9,918	0	0	0
37	9080	383,888	0	0	75,759	297,231	17,381	360,790	0	0	75,759	297,231	17,381	23,098	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	47,279	549,418	3,763,913	236,670	5,209,994	34,863,770	45,225	516,401	3,605,726	236,670	5,209,021	34,862,873	2,055	33,017	158,186	0	973	897
41	9210	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0
42	9260	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	9280	0	910	0	0	0	0	0	0	0	0	0	0	0	910	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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
45	Total Expense	$7,332,774	$4,165,801	$4,854,620	$1,880,405	$7,317,664	$38,192,156	$5,986,801	$3,972,961	$4,676,439	$1,876,118	$7,315,318	$38,191,258	$1,345,973	$192,841	$178,182	$4,287	$2,346	$897
46	Total Test Year	$12,794,856	$5,500,519	$5,592,504	$4,641,081	$9,656,799	$46,513,158	$10,519,747	$5,190,445	$5,386,813	$4,633,817	$9,654,047	$46,512,247	$2,275,109	$310,074	$205,691	$7,264	$2,752	$912
47	Payroll Expense Factor	53%	76%	83%															
48	Overtime Factor	22%	6%	4%															

Source: WKP G-4.b and WKP G-4.c Test Year and June Payroll Direct and Shared Service(CONFIDENTIAL).xlsx
Source: WKP G-4.b and WKP G-4.c Test Year and June Payroll Corporate(CONFIDENTIAL).xlsx

WKP G-4.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$9,334
2	1540	0	0	0	0	0	0
3	1630	13,393	0	0	5,407	0	1,706
4	1840	369,753	96,880	65,252	188,056	268,532	795,804
5	1860	0	0	0	0	0	0
6	2530	5,609	0	0	$17,883	0	0
7	Total Capital	$388,755	$96,880	$65,252	$211,346	$268,532	$806,844
	Expense						
8	8500	$0	$0	$0	$0	$0	$6,517
9	8530	0	0	10,787	0	7,377	6,595
10	8560	11,043	47	0	618	0	0
11	8570	0	0	0	0	0	0
12	8590	0	0	0	0	0	2,672
13	8610	0	260	0	0	0	0
14	8630	0	0	0	0	0	0
15	8650	0	4,919	7,831	0	33,998	106,316
16	8700	3,517	24,420	0	24,846	7,873	0
17	8710	0	0	5,798	0	2,108	16,821
18	8740	43,214	8,220	0	22,970	0	0
19	8750	7,449	4,178	0	8,075	4,081	0
20	8760	0	390	0	875	583	0
21	8770	0	0	8,780	0	0	5,044
22	8780	165,446	0	0	19,817	0	0
23	8790	2,872	428	8,065	0	30,582	0
24	8800	31,559	0	0	10,266	0	11,949
25	8850	0	0	0	0	0	0
26	8860	0	6,979	0	0	0	0
27	8870	86,158	0	0	12,032	0	0
28	8890	11,471	2,872	0	4,863	0	0
29	8900	22,487	0	0	4,862	0	0
30	8910	799	0	0	0	0	0
31	8920	21,034	0	0	1,842	0	0
32	8930	0	2,923	0	0	18,576	275

WKP G-4.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
33	9010	0	0	0	0	0	0
34	9020	29,983	223,454	0	3,713	80,482	0
35	9030	4,166	0	42,787	0	0	131,521
36	9050	117	0	0	0	27,219	17,381
37	9080	27,304	0	0	5,398	0	0
38	9120	0	0	0	0	0	0
39	9130	0	41,016	331,746	0	446,158	3,001,068
40	9200	940	0	0	18,988	0	0
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	$469,560	$320,107	$415,793	$139,166	$659,037	$3,306,160
47	Total Base Payroll	$858,315	$416,986	$481,045	$350,513	$927,569	$4,113,004

Source: WKP G-4.b and WKP G-4.c Test Year and June Payroll Direct and Shared Service(CONFIDENTIAL).xlsx
Source: WKP G-4.b and WKP G-4.c Test Year and June Payroll Corporate(CONFIDENTIAL).xlsx

SCHEDULE G-5

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$11,158,091	$5,420,822	$6,253,579	
2	Overtime as a % of Hourly Base Payroll (Actual for the Test Period)	WKP G-4.b	22%	6%	4%	
3	Total Annualized Overtime Payroll (Ln 1 times Ln 2)		$2,413,164	$323,837	$238,788	
4	Test Period Overtime Payroll	WKP G-4.b	2,275,109	310,074	205,691	
5	Overtime Payroll Adjustment Total (Ln 3 minus Ln 4)		$138,055	$13,763	$33,097	
6	Allocation to TGS		100.00%	100.00%	25.01%	
7	Allocated Base Payroll Adjustment to TGS (Ln 5 times Ln 6)		$138,055	$13,763	$8,277	
8	Allocation to Service Area	WKP A.b	100.00%	46.49%	46.49%	
9	Allocated Base Payroll Adjustment to Service Area (Ln 7 times Ln 8)		$138,055	$6,399	$3,848	
10	Payroll Expense Factor	WKP G-4.b	53%	76%	83%	
11	Test Year Base Payroll O&M Expense Adjustment (Ln 9 times Ln 10)		$72,948	$4,848	$3,179	
	Adjustment Summary:					
12	Account 9302		$0	$0	$3,179	$3,179
13	Other O&M Accounts (See WKP G-5.a for Distribution by FERC Account)		72,948	4,848	0	77,796
14	Total (Ln 12 plus Ln 13)		$72,948	$4,848	$3,179	$80,976
15	Total Test Year Overtime Expense after Allocation		$1,202,172	$109,221	$19,759	$1,331,152
16	Total As Adjusted Overtime Expense after Allocation		1,275,120	114,068	22,939	1,412,127

WKP G-5.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	2,064	0.02%	1
3	8560	152,177	1.65%	1,205	8560	86,589	0.75%	37
4	8570	0	0.00%	0	8570	336	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	231	0.00%	2	8630	1,530	0.01%	1
8	8650	0	0.00%	0	8650	1,463	0.01%	1
9	8700	275,452	2.99%	2,181	8700	382,939	3.33%	162
10	8710	0	0.00%	0	8710	473,818	4.13%	200
11	8740	859,379	9.33%	6,804	8740	25,661	0.22%	11
12	8750	178,934	1.94%	1,417	8750	68,771	0.60%	29
13	8760	22,254	0.24%	176	8760	74,921	0.65%	32
14	8770	0	0.00%	0	8770	6,442	0.06%	3
15	8780	2,965,328	32.19%	23,479	8780	0	0.00%	0
16	8790	85,878	0.93%	680	8790	9	0.00%	0
17	8800	482,409	5.24%	3,820	8800	136,066	1.18%	57
18	8850	0	0.00%	0	8850	0	0.00%	0
19	8860	0	0.00%	0	8860	0	0.00%	0
20	8870	1,648,914	17.90%	13,056	8870	142,034	1.24%	60
21	8890	269,277	2.92%	2,132	8890	6,869	0.06%	3
22	8900	416,013	4.52%	3,294	8900	47,013	0.41%	20
23	8910	16,192	0.18%	128	8910	115	0.00%	0
24	8920	446,706	4.85%	3,537	8920	0	0.00%	0
25	8930	6,477	0.07%	51	8930	0	0.00%	0
26	9010	0	0.00%	0	9010	244,355	2.13%	103
27	9020	479,768	5.21%	3,799	9020	0	0.00%	0
28	9030	151,650	1.65%	1,201	9030	3,724,915	32.44%	1,572
29	9050	12,544	0.14%	99	9050	0	0.00%	0
30	9080	459,647	4.99%	3,639	9080	297,231	2.59%	125
31	9120	0	0.00%	0	9120	0	0.00%	0
32	9130	0	0.00%	0	9130	0	0.00%	0
33	9200	283,949	3.08%	2,248	9200	5,759,412	50.15%	2,431
34	9210	0	0.00%	0	9210	1	0.00%	0
35	9260	0	0.00%	0	9260	0	0.00%	0
36	9301	0	0.00%	0	9301	910	0.01%	0
37	9302	0	0.00%	0	9302	0	0.00%	0
38	9320	0	0.00%	0	9320	0	0.00%	0
39	Total	$9,213,179	100.00%	$72,948	Total	$11,483,465	100.00%	$4,848

SCHEDULE G-6

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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		$18,371,143		$17,515,103		$57,610,562	
2	BENEFITS COMPUTED PER PAYROLL $								
3	H&W BENEFITS*	WKP G-6.b	16.44%	$3,020,883	16.44%	$2,880,119	10.86%	$6,257,372	
4	PENSION	WKP G-6.b	7.22%	1,327,044	7.22%	1,265,207	8.75%	5,039,874	
5	OPEB	WKP G-6.b	0.34%	61,693	0.34%	58,818	0.10%	59,143	
6	SERP	WKP G-6.b	0.01%	1,269	0.01%	0	3.76%	0	
7	401K & NQDC	WKP G-6.b	4.91%	902,522	4.91%	860,467	5.22%	3,009,536	
8	PROFIT SHARING	WKP G-6.b	3.43%	630,410	3.43%	601,035	3.16%	1,821,783	
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	-0.89%	(163,504)	-0.89%	(155,885)	-0.54%	(310,352)	
11	A&G EMPL BEN STOCK RECEIVED	WKP G-6.b	0.00%	0	0.00%	0	0.00%	0	
				$5,780,317		$5,509,761		$15,877,355	
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		697,218	
15	A&G EMPL BEN MISC ADMIN	WKP G-6.b		0		0		(5,686)	
16	A&G EMPL BEN FAS 112	WKP G-6.b		0		0		11,640	
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		-	
19	A&G EMPL BEN ACCR 401(K) CO MATCH - STI	WKP G-6.b		0		195,142		469,138	
20	A&G EMPL BEN ACCR PSP ON STI	WKP G-6.b		0		125,805		308,297	
21	A&G EMPL BEN SCHOLARSHIPS	WKP G-6.b		0		0		118,405	
22	A&G EMPL BEN TUITION LOANS	WKP G-6.b		772		60,706		78,331	
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		-	
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		21,489		3,369		-	
27	A&G EMPL BEN SVC RECOGNITION	WKP G-6.b		0		55,600		40,600	
28	A&G EMPL BEN STOCK RECEIVED	WKP G-6.b		0		0		-	
29	A&G EMPL BEN EMPLOYEE REFERRAL	WKP G-6.b		0		0		103,000	
30	A&G EMPL BEN DRUG & ALCOHOL TESTING	WKP G-6.b		0		36		141,510	
31	A&G EMPL BEN EMPL ASST PROGRAM	WKP G-6.b		0		0		97,776	
32	A&G EMPL BEN CHEMICAL DEPENDENCY TREATMENT	WKP G-6.b		0		0		-	
33	A&G EMPL BEN DISABILITY	WKP G-6.b		0		0		-	
34	A&G EMPL BEN ACCOMMODATIONS	WKP G-6.b		0		0		493	
35	A&G EMPL BEN WELLNESS PROGRAM	WKP G-6.b		0		0		48,946	
36	A&G EMPL BEN MEDICAL CLINIC	WKP G-6.b		0		0		55,449	
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	
				$22,261		$440,658		$2,165,118	
39	Annualized Test Year Benefits			$5,802,578		$5,950,420		$18,042,473	

SCHEDULE G-6

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
40	PAYROLL TAX RATE PER PAYROLL $	WKP G-6.b	7.60%	$1,396,481	7.60%	$1,331,409	6.82%	$3,927,566	
41	Total Annualized Benefits and Payroll Tax			$7,199,059		$7,281,829		$21,970,039	
42	Test Year Benefits and Payroll Tax			5,442,779		9,085,739		17,038,941	
43	Allocable Adjustment to Benefits and Payroll Tax			$1,756,279		($1,803,910)		$4,931,098	
44	Allocation to TGS			100%		100%		25.01%	
45	Allocated Benefits and Payroll Tax Adjustment to TGS			$1,756,279		($1,803,910)		$1,233,268	
46	Allocation to Service Area	WKP A.b		100%		46.49%		46.49%	
47	Allocated Benefits and Payroll Tax Adjustment to Service Area			$1,756,279		($838,694)		573,384	
48	Payroll Expense Factor	WKP G-4.b		53%		76%		83%	
49	Test Year Benefits and Payroll Tax Adjustment			$928,021		($635,410)		$473,698	
50	Adjustment Summary:								
51	Account 9302			$0		$0		$473,698	$473,698
52	Other O&M Accounts (See WKP G4a for Distribution by FERC Account)			928,021		(635,410)		0	292,611
53	Total			$928,021		($635,410)		$473,698	$766,309

* 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		$2,875,974	$3,200,364	$1,636,818	$7,713,156
Total As Adjusted Benefits and Payroll Tax Expense after Allocation		3,803,995	2,564,954	2,110,516	8,479,465
	Taxes only	$737,903	$468,976	$377,295	$1,584,174

Source: SCH G-6 Direct Test Year Benefits and Payroll Taxes - CGSA.xlsx
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 - CGSA.xlsx

WKP G-6.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$1,376,115	20.23%	$187,757	4081	$1,196,277	20.23%	($128,556)
2	8560	0	0.00%	0	8560	0	0.00%	0
3	8570	0	0.00%	0	8570	0	0.00%	0
4	8590	0	0.00%	0	8590	0	0.00%	0
5	8610	0	0.00%	0	8610	0	0.00%	0
6	8630	0	0.00%	0	8630	0	0.00%	0
7	8650	0	0.00%	0	8650	0	0.00%	0
8	8700	0	0.00%	0	8700	0	0.00%	0
9	8710	0	0.00%	0	8710	0	0.00%	0
10	8740	0	0.00%	0	8740	0	0.00%	0
11	8750	0	0.00%	0	8750	0	0.00%	0
12	8760	0	0.00%	0	8760	0	0.00%	0
13	8770	0	0.00%	0	8770	0	0.00%	0
14	8780	0	0.00%	0	8780	0	0.00%	0
15	8790	0	0.00%	0	8790	0	0.00%	0
16	8800	0	0.00%	0	8800	0	0.00%	0
17	8850	0	0.00%	0	8850	0	0.00%	0
18	8860	0	0.00%	0	8860	0	0.00%	0
19	8870	0	0.00%	0	8870	0	0.00%	0
20	8890	0	0.00%	0	8890	0	0.00%	0
21	8900	0	0.00%	0	8900	0	0.00%	0
22	8910	0	0.00%	0	8910	0	0.00%	0
23	8920	0	0.00%	0	8920	0	0.00%	0
24	8930	0	0.00%	0	8920	0	0.00%	0
25	9010	0	0.00%	0	9010	0	0.00%	0
26	9020	0	0.00%	0	9020	0	0.00%	0
27	9030	0	0.00%	0	9030	0	0.00%	0
28	9050	0	0.00%	0	9050	0	0.00%	0
29	9080	0	0.00%	0	9080	0	0.00%	0
30	9120	0	0.00%	0	9120	0	0.00%	0
31	9130	0	0.00%	0	9130	0	0.00%	0
32	9200	0	0.00%	0	9200	0	0.00%	0
33	9210	0	0.00%	0	9210	0	0.00%	0
34	9260	4,066,665	79.77%	740,264	9260	7,889,231	79.77%	(506,854)
35	9302	0	0.00%	0	9302	0	0.00%	0
36	9320	0	0.00%	0	9320	0	0.00%	0
37	Total	$5,442,779	100.00%	$928,021	Total	$9,085,508	100.00%	($635,410)

WKP G-6.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

BENEFITS AND TAXES

LINE NO.		DESCRIPTION	TEXAS EMPLOYEES		CORPORATE SHARED SERVICE AND DISTRIGAS EMPLOYEES	
			(a)	(b)	(c)	(d)
	Based on Known and Measurable for June 2019					
		H&W Benefits				
1	9260190	A&G EMPL BEN RESERVE	$8,838,880		$6,317,011	
2	9260191	A&G EMPL BEN RESERVE UNION	0		0	
3			$8,838,880	16.44%	$6,317,011	10.86%
		Pension				
4	9260413	ONE GAS RETIREMENT PLAN SC	$2,340,674		$2,307,176	
5	9260513	ONE GAS RETIREMENT PLAN NSC	1,464,985		2,730,215	
6	9260115	EMPL BEN PENSION ADMIN	77,173		50,518	
			$3,882,832	7.22%	$5,087,909	8.75%
		OPEB				
7	9260431	OPEB SC	$100,355		$188,689	
8	9260531	OPEB NSC	80,153		(128,982)	
9	9260132	A&G EMPL BEN FAS 106 ADMIN	0		0	
			$180,508	0.34%	$59,707	0.10%
		SERP				
10	9260411	SERP SC			$571,003	
11	9260511	SERP NSC	$3,714		1,498,868	
12	9260112	A&G EMPL BEN SERP ADMIN			119,500	
			$3,714	0.01%	$2,189,371	3.76%
	Based on Test Year Data					
		401k & NQDC				
13	9260101	A&G EMPL BEN 401(K) CO MATCH	$2,586,102		$2,684,859	
14	9260102	A&G EMPL BEN 401(K) ADMIN	53,104		44,649	
15	9260103	A&G EMPL BEN DEF COMP CO MATCH	1,508		283,530	
16	9260104	A&G EMPL BEN DEF COMP ADMIN	0		25,181	
			$2,640,713	4.91%	$3,038,219	5.22%
		Profit Sharing Plan				
17	9260141	A&G EMPL BEN PROFIT SHARING	$1,787,315		$47,135	
18	9260140	A&G EMPL BEN PROFIT SHARING ADMIN	57,219		1,792,011	
			$1,844,534	3.43%	$1,839,146	3.16%
		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	(478,400)	-0.89%	(313,310)	-0.54%
21	9260312	A&G EMPL BEN STOCK RECEIVED	0	0.00%		0.00%
			($478,400)		($313,310)	

WKP G-6.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

BENEFITS AND TAXES

LINE NO.		DESCRIPTION	TEXAS EMPLOYEES (a)	(b)	CORPORATE SHARED SERVICE AND DISTRIGAS EMPLOYEES (c)	(d)
		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		697,218	
24	9260118	A&G EMPL BEN MISC ADMIN	0		(5,686)	
25	9260119	A&G EMPL BEN FAS 112	0		11,640	
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	195,142		469,138	
29	9260198	A&G EMPL BEN ACCR PSP ON STI	125,805		308,297	
30	9260301	A&G EMPL BEN SCHOLARSHIPS	0		118,405	
31	9260302	A&G EMPL BEN TUITION LOANS	61,478		78,331	
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	24,858		0	
36	9260310	A&G EMPL BEN SVC RECOGNITION	55,600		40,600	
37	9260312	A&G EMPL BEN STOCK RECEIVED	0		0	
38	9260314	A&G EMPL BEN EMPLOYEE REFERRAL	0		103,000	
39	9260321	A&G EMPL BEN DRUG & ALCOHOL TESTING	36		141,510	
40	9260326	A&G EMPL BEN EMPL ASST PROGRAM	0		97,776	
41	9260327	A&G EMPL BEN CHEMICAL DEPENDENCY TREATMENT	0		0	
42	9260328	A&G EMPL BEN DISABILITY	0		0	
43	9260329	A&G EMPL BEN ACCOMMODATIONS	0		493	
44	9260337	A&G EMPL BEN WELLNESS PROGRAM	0		48,946	
45	9260338	A&G EMPL BEN MEDICAL CLINIC	0		55,449	
46	9260340	A&G EMPL BEN EMPL APPL LOANS	0		0	
47	9260901	A&G EMPL BEN INTERCO PARKING	0		0	
			$462,919		$2,165,118	
	Based on Known and Measurable for June 2019					
		Payroll Taxes				
48	4081102	GEN TAX FICA	$3,946,000	7.34%	$3,906,000	6.72%
49	4081101	GEN TAX FED UNEMPL INS TAX	37,000	0.07%	26,000	0.04%
50	4081103	GEN TAX FICA INCENTIVE	103,000	0.19%	33,000	0.06%
51	4081132	GEN TAX STATE UNEMPL INS	0	0.00%	0	0.00%
			$4,086,000	7.60%	$3,965,000	6.82%
52		Total Benefit and Payroll Expense	$21,461,700		$24,348,171	
53		Total Labor*	$53,752,608	39.07%	$58,159,649	38.14%
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.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

AMORTIZATION OF PENSION & OTHER POST EMPLOYMENT BENEFITS

LINE NO.	YEAR ENDED DECEMBER 2017	BEGINNING OF YEAR RATE BASE ADJUSTMENT AMOUNT	ANNUAL AMMORTIZATION	END OF YEAR RATE BASE ADJUSTMENT AMOUNT	ANNUAL AMMORTIZATION
	(a)	(b)	(c)	(d)	(e)
1	2018			$1,704,879	
2	2019	$1,704,879		1,704,879	
3	2020	1,704,879	$284,147	1,420,733	
4	2021	1,420,733	284,147	1,136,586	
5	2022	1,136,586	284,147	852,440	
6	2023	852,440	284,147	568,293	
7	2024	568,293	284,147	284,147	
8	2025	284,147	284,147	0	
9	Annualized Amortization of Pension & Other Post Employment Benefits Reg Asset - Account 4073				$284,147
10	Test Year Pension & Other Post Employment Benefits Reg Asset Amortization Expense - Account 4073				289,452
11	Total Adjustment to Test Period Expense				($5,306)

SCHEDULE G-8

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

INCENTIVE COMPENSATION

			Corporate Allocated to TGS							ALLOCATED TO CGSA		
LINE NO.	DESCRIPTION	ACCT. 'NO.	UNALLOCATED CORPORATE PER BOOK	ADJUSTMENT TO REMOVE 5 NAMED OFFICERS	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 CENTRAL-GULF	TOTAL ADJUSTMENT AS ALLOCATED TO CENTRAL-GULF	TOTAL TEST YEAR ADJUSTED AS ALLOCATED TO CENTRAL-GULF
										46.4931%		
1	GEN TAX FICA INCENTIVE	4081	$626,000	($30,912)	$595,088	25.01%	$156,563	($7,731)	$148,832	$72,791	($3,594)	$69,196
2	A&G SALARIES INCENTIVE PLAN	9302	10,722,000	(1,514,034)	9,207,966	25.01%	2,681,572	(378,660)	2,302,912	1,246,746	(176,051)	1,070,695
3	A&G EMPL BEN ACCR 401(K) CO MATCH	9302	512,000	(55,900)	456,100	25.01%	128,051	(13,981)	114,071	59,535	(6,500)	53,035
4	A&G EMPL BEN ACCR PSP ON STI	9302	172,000	(24,225)	147,775	25.01%	43,017	(6,059)	36,959	20,000	(2,817)	17,183
5	TOTAL SHORT TERM INCENTIVE		$12,032,000	($1,625,071)	$10,406,929		$3,009,203	($406,430)	$2,602,773	$1,399,072	($188,962)	$1,210,110
6	A&G SALARIES LT INCENT-RESTRICTED	9302	$1,703,709		$1,703,709	25.01%	$426,098	$0	$426,098	$198,106	$0	$198,106
7	A&G SALARIES LT INCENT-PERFORMANCE	9302	4,514,756	(2,722,353)	1,792,403	25.01%	1,129,140	(680,860)	448,280	524,972	(316,553)	208,419
8	TOTAL LONG TERM INCENTIVE		$6,218,465	($2,722,353)	$3,496,112	25.01%	$1,555,238	($680,860)	$874,378	$723,078	($316,553)	$406,525

			TGS			ALLOCATED TO CGSA		
LINE NO.	DESCRIPTION	ACCT. 'NO.	TGS PER BOOK	ADJUSTMENT TO REMOVE 5 NAMED OFFICERS	TGS ADJUSTED TEST YEAR	TOTAL PER BOOK AS ALLOCATED TO CENTRAL-GULF	TOTAL ADJUSTMENT AS ALLOCATED TO CENTRAL-GULF	TOTAL TEST YEAR ADJUSTED AS ALLOCATED TO CENTRAL-GULF
						46.4931%		
	Short Term Incentive							
1	GEN TAX FICA INCENTIVE	4081	$246,000	$0	$246,000	$114,373	$0	$114,373
2	A&G SALARIES INCENTIVE PLAN	9200	4,239,101	0	4,239,101	1,970,890	0	1,970,890
3	A&G EMPL BEN ACCR 401(K) CO MATCH	9260	201,000	0	201,000	93,451	0	93,451
4	A&G EMPL BEN ACCR PSP ON STI	9260	68,000	0	68,000	31,615	0	31,615
5	TOTAL SHORT TERM INCENTIVE		$4,754,101	$0	$4,754,101	$2,210,329	$0	$2,210,329
6								
7	A&G SALARIES LT INCENT-RESTRICTED	9200	$239,509	$0	$239,509	$111,355	$0	$111,355
8	A&G SALARIES LT INCENT-PERFORMANCE	9200	146,602	0	146,602	68,160	0	68,160
9	TOTAL LONG TERM INCENTIVE		$386,111	$0	$386,111	$179,515	$0	$179,515
	Total Test Year Incentive Compensation after Allocation					$4,511,994		
	Total As Adjusted Benefits and Payroll Tax Expense after Allocation					$4,006,479		

Source: SCH G-8 Incentive Compensation per book (CONFIDENTIAL).xlsx
Source: SCH G-8 Adjustment

SCHEDULE G-9

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$814,781	($784,431)	$0	$30,350
2	Transmission O & M - Mains Expenses	8560	0	(4)	0	(4)
3	Transmission Other Misc Expenses	8590	0	(4)	0	(4)
4	Maintenance of Mains	8630	0	0	0	0
5	Distr. Operations- General Supervision	8700	(204)	(693)	0	(897)
6	Distr. Operations - Distribution Load Dispatch	8710	0	(412)	0	(412)
7	Distr. Operations - Mains & Services	8740	(126)	0	0	(126)
8	Distr Meas & Reg St Misc	8750	(1,730)	0	0	(1,730)
9	Distr. Operations - Meter & House Reg. Exp.	8780	(5)	(0)	0	(5)
10	Distr. Operations - Other Expense	8800	179,240	(88)	0	179,152
11	Distr. Operations - Rents	8810	0	0	0	0
12	Distr. Operations - Struct. & Improv.	8860	0	0	0	0
13	Distr. Maintenance - Mains	8870	(0)	(0)	0	(1)
14	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0
15	Distr. Maintenance - Ind .Meas. & Reg. Stat. Misc.	8900	(45)	0	0	(45)
16	Customer Accounting - Supervision	9010	0	(993)	0	(993)
17	Customer Accounting - Meter Reading	9020	0	0	0	0
18	Customer Accounting - Rec. Coll. Misc. Expense	9030	0	(1,806)	0	(1,806)
19	Customer Accounting - Bad Debt	9040	0	0	0	0
20	Customer Accounting - Misc. Expense	9050	0	(6)	0	(6)
21	Customer Assistance-Misc. Expense	9080	(189)	(287)	0	(476)
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090	0	(104)	0	(104)
23	Demo/Sell- Misc. Expenses	9120	0	0	0	0
24	Advertising-Misc. Expense	9130	0	0	0	0
25	Salaries	9200	0	0	0	0
26	Admin & Gen - Office Supp & Exp	9210	(323,513)	328,488	0	4,975
27	Admin & Gen - Outside Services	9230	0	(4,248)	0	(4,248)
28	Property Insurance	9240	0	26,737	0	26,737
29	Admin & Gen - Injuries & Damages	9250	0	211,383	0	211,383
30	Admin & Gen - Employee Pensions & Benefits	9260	1,695,726	(1,632,616)	(181,259)	(118,149)
31	Admin & Gen - Regulatory Commission Expense	9280	0	0	0	0
32	Admin & Gen - Labor Attends Credit	9290	0	0	0	0
33	Admin & Gen - Advertising	9301	0	0	0	0
34	Admin & Gen - Misc General	9302	(486)	(2,862,145)	(235,302)	(3,097,933)
35	Admin & Gen - Rents	9310	0	0	0	0
36	Totals		$2,363,448	($4,721,230)	($416,561)	($2,774,342)

WKP G-9.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

MISCELLANEOUS ADJUSTMENTS
DIRECT SERVICE AREA

LINE NO.	DESCRIPTION	ACCT	REMOVAL OF CLUBS AND CIVIC EXPENSE	Adjustment to include Direct Benefits and Payroll Related Taxes	Adjustment to include Direct O/H for Payroll Related Taxes and Benefits	Direct SERP with payroll factor applied	OTHER ADJUSTMENTS	TOTAL ADJUSTMENT TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)
1	Payroll Taxes	4081	$0	$1,376,115	($561,334)	$0	$0	$814,781
2	Transmission O & M - Mains Expenses	8560	0	0	0	0	0	0
3	Maintenance of Mains	8630	0	0	0	0	0	0
4	Distr. Operations- General Supervision	8700	0	0	0	0	(184)	(184)
5	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0	0	0
6	Distr Meas & Reg St Misc	8750	(1,385)	0	0	0	(345)	(1,730)
7	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	0	0	0
8	Distr. Operations - Other Expense	8800	0	0	0	0	179,519	179,519
9	Distr. Operations - Rents	8810	0	0	0	0	0	0
10	Distr. Maintenance - Mains	8870	0	0	0	0	0	0
11	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0	0	0
12	Distr. Maintenance- Cathodic Protection	8900	0	0	0	0	0	0
13	Customer Accounting - Supervision	9010	0	0	0	0	0	0
14	Customer Accounting - Meter Reading	9020	0	0	0	0	0	0
15	Customer Accounting - Bad Debts	9040	0	0	0	0	0	0
16	Customer Asst.- Misc. Expenses	9080	0	0	0	0	0	0
17	Demo/Sell- Misc. Expenses	9120	0	0	0	0	0	0
18	Admin & Gen - Office Supp & Exp	9210	(2,060)	0	0	0	(321,261)	(323,321)
19	Admin & Gen - Outside Services	9230	0	0	0	0	0	0
20	Admin & Gen - Injuries & Damages	9250	0	0	0	0	0	0
21	Admin & Gen - Employee Pensions & Benefits	9260	0	4,066,665	(2,371,248)	671	(362)	1,695,726
22	Admin & Gen - Regulatory Commission Expense	9280	0	0	0	0	0	0
23	Admin & Gen - Misc General	9302	0	0	0	0	(454)	(454)
24	Admin & Gen - Rents	9310	0	0	0	0	0	0
25	Totals		($3,445)	$5,442,779	($2,932,581)	$671	($143,087)	$2,364,337

Source: WKP G-9.a CGSA Civic Charitable Misc Adjustments.xlsx
Source: WKP G-9.a CGSA Communications (CONFIDENTIAL).xlsx
Source: WKP G-9.a OTC Reimbursement Adjustment CGSA.xlsx
Source: SCH G-6 Shared Service Test Year Benefits and Payroll Taxes - CGSA.xlsx

WKP G-9.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

MISCELLANEOUS ADJUSTMENTS
SHARED SERVICES

LINE NO.	CATEGORY	To Cc	Tocostcenter Description	FERC Account	Natural Account	Account Description	Adjustment for Known and measurable change in Insurance premiums (a)	Adjustment to remove costs associated with Royalty fees (b)	Management decision to not seek recovery (c)	Remove - Rule 7.5414 Contributions, donations to charitable, religious, or other nonprofit organizations (d)	Remove portion of AGA dues attributable to lobbying. (e)	Remove Stock Award Activity as the program ended (f)	Telecom Reclass (g)	Adjustment to Remove Payroll Related Taxes and Benefits (h)	Adjustment to Included Shared Service Payroll Related Taxes and Benefits (i)	Adjustment to Remove total O/H for Payroll Related Taxes and Benefits (j)	Adjustment to include Shared Services portion of O/H for Payroll Related Taxes and Benefits (k)	Grand Total (l)	O&M EXPENSE FACTOR (m)	ALLOCATION TO SERVICE AREA (n)	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT (o)
1	Causal	1621	OGS HR PLAN ADMINISTRATION	9260	9260102	A&G EMPL BEN 401(K) ADMIN								(53,104)				(53,104)			
2	Causal	1621	OGS HR PLAN ADMINISTRATION	9260	9260112	A&G EMPL BEN SERP ADMIN								(153)				(153)			
3	Causal	1621	OGS HR PLAN ADMINISTRATION	9260	9260115	A&G EMPL BEN PENSION ADMIN								13,865				13,865			
4	Causal	1621	OGS HR PLAN ADMINISTRATION	9260	9260140	A&G EMPL BEN PROFIT SHARING ADMIN								(57,219)				(57,219)			
5	Causal	1621	OGS HR PLAN ADMINISTRATION	**9260 Total**										**(96,610)**				**(96,610)**	**88.69%**	**46.4931%**	**(39,837)**
6	Causal	1931	OGS RM RESOURCE SUPPLY	9302	9302311	A&G MISC OGS VOLUNTEERS				(3)								(3)			
7	Causal	1931	OGS RM RESOURCE SUPPLY	**9302 Total**						**(3)**								**(3)**	**88.69%**	**46.4931%**	**(1)**
8	Causal	1938	OGS ENG QUALITY AND COMPLIANCE	9302	9302311	A&G MISC OGS VOLUNTEERS				(127)								(127)			
9	Causal	1938	OGS ENG QUALITY AND COMPLIANCE	**9302 Total**						**(127)**								**(127)**	**88.69%**	**46.4931%**	**(52)**
10	Causal	1953	OGS PROCESS IMPROVEMENT & CUSTOMER EXPERIENCE	9302	9302311	A&G MISC OGS VOLUNTEERS				(6)								(6)			
11	Causal	1953	OGS PROCESS IMPROVEMENT & CUSTOMER EXPERIENCE	**9302 Total**						**(6)**								**(6)**	**88.69%**	**46.4931%**	**(2)**
12	Shared Service	0	COMMON	4081	4081100	GEN TAX O/H TRF TO CAPITAL										1,108,209	(487,980)	620,229			
13	Shared Service	0	COMMON	4081	4081101	GEN TAX FED UNEMPL INS TAX								(39,363)	1,196,277			1,156,914			
14	Shared Service	0	COMMON	4081	4081102	GEN TAX FICA								(3,959,788)				(3,959,788)			
15	Shared Service	0	COMMON	4081	4081132	GEN TAX STATE UNEMPL INS								(106,345)				(106,345)			
16	Shared Service	0	COMMON	**4081 Total**										**(4,105,497)**	**1,196,277**	**1,108,209**	**(487,980)**	**(2,288,991)**	**88.69%**	**46.4931%**	**(943,872)**
17	Shared Service	0	COMMON	9260	9260902	A&G EMPL BEN O/H TRF CAPITAL										(2,272)	(1,872,461)	(1,874,733)			
18	Shared Service	0	COMMON	9260	9260905	A&G EMPL BEN O/H TRF CAPITAL - NSC										(33)	(188,899)	(188,932)			
19	Shared Service	0	COMMON	**9260 Total**												**(2,305)**	**(2,061,360)**	**(2,063,665)**	**88.69%**	**46.4931%**	**(850,959)**
20	Shared Service	1000	OGS GENERAL	4081	4081103	GEN TAX FICA INCENTIVE								(303,699)				(303,699)			
21	Shared Service	1000	OGS GENERAL	**4081 Total**										**(303,699)**				**(303,699)**	**88.69%**	**46.4931%**	**(125,231)**
22	Shared Service	1000	OGS GENERAL	9260	9260197	A&G EMPL BEN ACCR 401(K) CO MATCH - STI								(195,142)				(195,142)			
23	Shared Service	1000	OGS GENERAL	9260	9260198	A&G EMPL BEN ACCR PSP ON STI								(125,805)				(125,805)			
24	Shared Service	1000	OGS GENERAL	9260	9260312	A&G EMPL BEN STOCK RECEIVED						(850)						(850)			
25	Shared Service	1000	OGS GENERAL	**9260 Total**								**(850)**		**(320,947)**				**(321,797)**	**88.69%**	**46.4931%**	**(132,694)**
26	Shared Service	1000	OGS GENERAL	9302	9302106	A&G MISC AGA INDUSTRY DUES					(2,698)							(2,698)			
27	Shared Service	1000	OGS GENERAL	**9302 Total**							**(2,698)**							**(2,698)**	**88.69%**	**46.4931%**	**(1,112)**
28	Shared Service	1014	OGS COMMUNITY RELATIONS	8700	8700100	DISTR GEN SUPERVISION				32								32			
29	Shared Service	1014	OGS COMMUNITY RELATIONS	**8700 Total**						**32**								**32**	**88.69%**	**46.4931%**	**13**
30	Shared Service	1014	OGS COMMUNITY RELATIONS	9302	9302311	A&G MISC OGS VOLUNTEERS			(7,490)	(5,761)								(13,251)			
31	Shared Service	1014	OGS COMMUNITY RELATIONS	**9302 Total**					**(7,490)**	**(5,761)**								**(13,251)**	**88.69%**	**46.4931%**	**(5,464)**
32	Shared Service	1106	OGS LEGAL TGS	9210	9210102	A&G S&E EMPL MISC			(41)									(41)			
33	Shared Service	1106	OGS LEGAL TGS	**9210 Total**					**(41)**									**(41)**	**88.69%**	**46.4931%**	**(17)**
34	Shared Service	1106	OGS LEGAL TGS	9230	9230115	A&G OUTSIDE SVC LEGAL REGULATORY			(10,301)									(10,301)			
35	Shared Service	1106	OGS LEGAL TGS	**9230 Total**					**(10,301)**									**(10,301)**	**88.69%**	**46.4931%**	**(4,248)**
36	Shared Service	1113	OGS ADMIN RISK & INS	9240	9240100	A&G PROPERTY INSURANCE	64,840											64,840			
37	Shared Service	1113	OGS ADMIN RISK & INS	**9240 Total**			**64,840**											**64,840**	**88.69%**	**46.4931%**	**26,737**
38	Shared Service	1113	OGS ADMIN RISK & INS	9250	9250100	A&G INSURANCE	432											432			
39	Shared Service	1113	OGS ADMIN RISK & INS	9250	9250120	A&G INJ & DAMAGES WORKERS COMP	(6,634)											(6,634)			
40	Shared Service	1113	OGS ADMIN RISK & INS	9250	9250180	A&G INJ & DAMAGES LIABILITY INSURANCE	518,828											518,828			
41	Shared Service	1113	OGS ADMIN RISK & INS	**9250 Total**			**512,626**											**512,626**	**88.69%**	**46.4931%**	**211,383**
42	Shared Service	1512	OGS IT FIELD SERVICES	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT			(12)									(12)			
43	Shared Service	1512	OGS IT FIELD SERVICES	**9210 Total**					**(12)**									**(12)**	**88.69%**	**46.4931%**	**(5)**
44	Shared Service	1620	OGS WORKFORCE DEVELOPMENT PLANS	9210	9210809	A&G S&E EMPLOYEE ONBOARDING PROGRAM			(14)									(14)			
45	Shared Service	1620	OGS WORKFORCE DEVELOPMENT PLANS	**9210 Total**					**(14)**									**(14)**	**88.69%**	**46.4931%**	**(6)**
46	Shared Service	1620	OGS WORKFORCE DEVELOPMENT PLANS	9260	9260302	A&G EMPL BEN TUITION LOANS								(60,706)				(60,706)			
47	Shared Service	1620	OGS WORKFORCE DEVELOPMENT PLANS	9260	9260310	A&G EMPL BEN SVC RECOGNITION								(55,600)				(55,600)			
48	Shared Service	1620	OGS WORKFORCE DEVELOPMENT PLANS	9260	9260321	A&G EMPL BEN DRUG & ALCOHOL TESTING								(36)				(36)			
49	Shared Service	1620	OGS WORKFORCE DEVELOPMENT PLANS	**9260 Total**										**(116,342)**				**(116,342)**	**88.69%**	**46.4931%**	**(47,974)**
50	Shared Service	1621	OGS HR PLAN ADMINISTRATION	9260	9260115	A&G EMPL BEN PENSION ADMIN								(22,538)				(22,538)			
51	Shared Service	1621	OGS HR PLAN ADMINISTRATION	**9260 Total**										**(22,538)**				**(22,538)**	**88.69%**	**46.4931%**	**(9,294)**
52	Shared Service	1622	OGS HEALTH & WELFARE	9260	9260190	A&G EMPL BEN RESERVE								(8,693,355)				(8,693,355)			
53	Shared Service	1622	OGS HEALTH & WELFARE	9260	9260192	A&G EMPL BEN RESERVE IBNR								478,400				478,400			
54	Shared Service	1622	OGS HEALTH & WELFARE	**9260 Total**										**(8,214,955)**				**(8,214,955)**	**88.69%**	**46.4931%**	**(3,387,462)**
55	Shared Service	1623	OGS RETIREMENT BENEFITS	9260	9260101	A&G EMPL BEN 401(K) CO MATCH								(2,586,102)				(2,586,102)			
56	Shared Service	1623	OGS RETIREMENT BENEFITS	9260	9260103	A&G EMPL BEN DEF COMP CO MATCH								(1,508)	7,889,231			7,887,723			
57	Shared Service	1623	OGS RETIREMENT BENEFITS	9260	9260141	A&G EMPL BEN PROFIT SHARING								(1,787,315)				(1,787,315)			
58	Shared Service	1623	OGS RETIREMENT BENEFITS	9260	9260413	A&G EMPL BEN ACTUARY ONE GAS PENSION-SC								(2,377,484)				(2,377,484)			
59	Shared Service	1623	OGS RETIREMENT BENEFITS	9260	9260431	A&G EMPL BEN ACTUARY OPEB-SC								(86,489)				(86,489)			
60	Shared Service	1623	OGS RETIREMENT BENEFITS	9260	9260511	A&G EMPL BEN ACTUARY SERP-NSC								(7,589)				(7,589)			
61	Shared Service	1623	OGS RETIREMENT BENEFITS	9260	9260513	A&G EMPL BEN ACTUARY ONE GAS PENSION-NSC								(1,711,315)				(1,711,315)			
62	Shared Service	1623	OGS RETIREMENT BENEFITS	9260	9260531	A&G EMPL BEN ACTUARY OPEB-NSC								(51,431)				(51,431)			
63	Shared Service	1623	OGS RETIREMENT BENEFITS	**9260 Total**										**(8,609,233)**	**7,889,231**			**(720,002)**	**88.69%**	**46.4931%**	**(296,895)**
64	Shared Service	1642	OGS SAFETY	8800	8800100	DISTR OTHER EXPENSES				(102)								(102)			
65	Shared Service	1642	OGS SAFETY	**8800 Total**						**(102)**								**(102)**	**88.69%**	**46.4931%**	**(42)**
66	Shared Service	1642	OGS SAFETY	9260	9260307	A&G EMPL BEN EMPLOYEE EVENTS								(3,350)				(3,350)			
67	Shared Service	1642	OGS SAFETY	**9260 Total**										**(3,350)**				**(3,350)**	**88.69%**	**46.4931%**	**(1,381)**
68	Shared Service	1932	OGS RM CONTRACTOR CTRL & OPTIMIZATION	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT				(53)								(53)			
69	Shared Service	1932	OGS RM CONTRACTOR CTRL & OPTIMIZATION	**9210 Total**						**(53)**								**(53)**	**88.69%**	**46.4931%**	**(22)**
70	Shared Service	1938	OGS ENG QUALITY AND COMPLIANCE	8700	8700100	DISTR GEN SUPERVISION				(251)								(251)			
71	Shared Service	1938	OGS ENG QUALITY AND COMPLIANCE	**8700 Total**						**(251)**								**(251)**	**88.69%**	**46.4931%**	**(104)**
72	Shared Service	1938	OGS ENG QUALITY AND COMPLIANCE	9210	9210100	A&G SUPPLIES & EXPENSES MISC				(3,667)								(3,667)			
73	Shared Service	1938	OGS ENG QUALITY AND COMPLIANCE	**9210 Total**						**(3,667)**								**(3,667)**	**88.69%**	**46.4931%**	**(1,512)**
74	Shared Service	7000	TGS GENERAL	4081	4081100	GEN TAX O/H TRF TO CAPITAL										690,360		690,360			
75	Shared Service	7000	TGS GENERAL	**4081 Total**												**690,360**		**690,360**	**88.69%**	**46.4931%**	**284,672**
76	Shared Service	7000	TGS GENERAL	9260	9260902	A&G EMPL BEN O/H TRF CAPITAL										6,903,732		6,903,732			
77	Shared Service	7000	TGS GENERAL	9260	9260905	A&G EMPL BEN O/H TRF CAPITAL - NSC										696,277		696,277			
78	Shared Service	7000	TGS GENERAL	**9260 Total**												**7,600,010**		**7,600,010**	**88.69%**	**46.4931%**	**3,133,887**
79	Shared Service	7000	TGS GENERAL	9302	9302915	A&G MISC ROYALTY ALLOCATED		(6,924,897)										(6,924,897)			
80	Shared Service	7000	TGS GENERAL	**9302 Total**				**(6,924,897)**										**(6,924,897)**	**88.69%**	**46.4931%**	**(2,855,502)**
81	Shared Service	7010	TGS EXECUTIVE	9210	9210201	A&G S&E ASSOC MTGS				(350)								(350)			
82	Shared Service	7010	TGS EXECUTIVE	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT				(71)								(71)			
83	Shared Service	7010	TGS EXECUTIVE	**9210 Total**						**(421)**								**(421)**	**88.69%**	**46.4931%**	**(174)**
84	Shared Service	7014	TGS COMMUNITY RELATIONS	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT				(49)								(49)			
85	Shared Service	7014	TGS COMMUNITY RELATIONS	**9210 Total**						**(49)**								**(49)**	**88.69%**	**46.4931%**	**(20)**
86	Shared Service	7014	TGS COMMUNITY RELATIONS	9302	9302105	A&G MISC INDUSTRY DUES			(25)									(25)			
87	Shared Service	7014	TGS COMMUNITY RELATIONS	**9302 Total**					**(25)**									**(25)**	**88.69%**	**46.4931%**	**(10)**
88	Shared Service	7016	TGS TECHNICAL TRAINING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT			(17)	(47)								(63)			
89	Shared Service	7016	TGS TECHNICAL TRAINING	9210	9210210	A&G S&E OFFICE SUPPLIES				(108)								(108)			
90	Shared Service	7016	TGS TECHNICAL TRAINING	**9210 Total**					**(17)**	**(155)**								**(172)**	**88.69%**	**46.4931%**	**(71)**
91	Shared Service	7018	TGS CUSTOMER BILLING	9030	9030110	CUST RECORDS EXPENSE				(2)								(2)			
92	Shared Service	7018	TGS CUSTOMER BILLING	**9030 Total**						**(2)**								**(2)**	**88.69%**	**46.4931%**	**(1)**
93	Shared Service	7021	TGS INFORMATION CENTER	9030	9030100	CUST REC/COLLEC EXP MISC			(101)									(101)			
94	Shared Service	7021	TGS INFORMATION CENTER	9030	9030110	CUST RECORDS EXPENSE			(2,974)	(219)								(3,193)			
95	Shared Service	7021	TGS INFORMATION CENTER	**9030 Total**					**(3,075)**	**(219)**								**(3,294)**	**88.69%**	**46.4931%**	**(1,358)**
96	Shared Service	7036	TGS COMMUNICATIONS	9090	9090321	INFO/INSTRUC CORP COMM DIRECT				(252)								(252)			
97	Shared Service	7036	TGS COMMUNICATIONS	**9090 Total**						**(252)**								**(252)**	**88.69%**	**46.4931%**	**(104)**
98	Shared Service	7038	TGS GIS	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT			(28)	(17)								(45)			

WKP G-9.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

MISCELLANEOUS ADJUSTMENTS
SHARED SERVICES

LINE NO.	CATEGORY	To Cc	Tocostcenter Description	FERC Account	Natural Account	Account Description	Adjustment for Known and measurable change in Insurance premiums (a)	Adjustment to remove costs associated with Royalty fees (b)	Management decision to not seek recovery (c)	Remove - Rule 7.5414 Contributions, donations to charitable, religious, or other nonprofit organizations (d)	Remove portion of AGA dues attributable to lobbying. (e)	Remove Stock Award Activity as the program ended (f)	Telecom Reclass (g)	Adjustment to Remove Payroll Related Taxes and Benefits (h)	Adjustment to Included Shared Service Payroll Related Taxes and Benefits (i)	Adjustment to Remove total O/H for Payroll Related Taxes and Benefits (j)	Adjustment to include Shared Services portion of O/H for Payroll Related Taxes and Benefits (k)	Grand Total (l)	O&M EXPENSE FACTOR (m)	ALLOCATION TO SERVICE AREA (n)	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT (o)
99	Shared Service	7038	TGS GIS	9210 Total					(28)	(17)								(45)	88.69%	46.4931%	(18)
100	Shared Service	7039	TGS OUTSIDE AREAS OPERATIONS	9260	9260307	A&G EMPL BEN EMPLOYEE EVENTS								(19)				(19)			
101	Shared Service	7039	TGS OUTSIDE AREAS OPERATIONS	9260 Total										(19)				(19)	88.69%	46.4931%	(8)
102	Shared Service	7042	TGS DIVISION MEASUREMENT & REGULATION	8790	8790100	DISTR CUST INSTALL MISC EXP			-									-			
103	Shared Service	7042	TGS DIVISION MEASUREMENT & REGULATION	8790 Total					-									-	88.69%	46.4931%	-
104	Shared Service	7044	TGS TRANSMISSION	8800	8800100	DISTR OTHER EXPENSES			(44)									(44)			
105	Shared Service	7044	TGS TRANSMISSION	8800 Total					(44)									(44)	88.69%	46.4931%	(18)
106	Shared Service	7045	TGS DIVISION LINE LOCATING	8800	8800100	DISTR OTHER EXPENSES			-									-			
107	Shared Service	7045	TGS DIVISION LINE LOCATING	8800 Total					-									-	88.69%	46.4931%	-
108	Shared Service	7045	TGS DIVISION LINE LOCATING	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT			-									-			
109	Shared Service	7045	TGS DIVISION LINE LOCATING	9210 Total					-									-	88.69%	46.4931%	-
110	Shared Service	7049	TGS CASH PROCESSING	9030	9030110	CUST RECORDS EXPENSE				(10)								(10)			
111	Shared Service	7049	TGS CASH PROCESSING	9030 Total						(10)								(10)	88.69%	46.4931%	(4)
112	Shared Service	7050	TGS CUSTOMER SVC ADMIN	9010	9010100	CUST ACCTG/COLL SUPERVISION			(1,058)	(625)								(1,683)			
113	Shared Service	7050	TGS CUSTOMER SVC ADMIN	9010 Total					(1,058)	(625)								(1,683)	88.69%	46.4931%	(694)
114	Shared Service	7050	TGS CUSTOMER SVC ADMIN	9030	9030100	CUST REC/COLLEC EXP MISC			(923)									(923)			
115	Shared Service	7050	TGS CUSTOMER SVC ADMIN	9030	9030228	CUST REC/COLLEC EXP PERS USE AUTO				(28)								(28)			
116	Shared Service	7050	TGS CUSTOMER SVC ADMIN	9030 Total					(923)	(28)								(951)	88.69%	46.4931%	(392)
117	Shared Service	7091	TGS COMMERCIAL PROJECT MANAGEMENT	9080	9080100	CUST ASST MISC EXP			(149)									(149)			
118	Shared Service	7091	TGS COMMERCIAL PROJECT MANAGEMENT	9080 Total					(149)									(149)	88.69%	46.4931%	(61)
119	Shared Service	7200	TGS CT GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES							19,551					19,551			
120	Shared Service	7200	TGS CT GENERAL	9210	9210304	A&G S&E CELLULAR PHONES							167,368					167,368			
121	Shared Service	7200	TGS CT GENERAL	9210	9210308	A&G S&E TELE DATA							23,575					23,575			
122	Shared Service	7200	TGS CT GENERAL	9210 Total									210,494					210,494	88.69%	46.4931%	86,798
123	Shared Service	7300	TGS ST GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES							1,589					1,589			
124	Shared Service	7300	TGS ST GENERAL	9210	9210304	A&G S&E CELLULAR PHONES							12,858					12,858			
125	Shared Service	7300	TGS ST GENERAL	9210	9210308	A&G S&E TELE DATA							1,208					1,208			
126	Shared Service	7300	TGS ST GENERAL	9210 Total									15,655					15,655	88.69%	46.4931%	6,455
127	Shared Service	7450	TGS ST GALVESTON GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES							3,504					3,504			
128	Shared Service	7450	TGS ST GALVESTON GENERAL	9210	9210304	A&G S&E CELLULAR PHONES							15,804					15,804			
129	Shared Service	7450	TGS ST GALVESTON GENERAL	9210	9210308	A&G S&E TELE DATA							14,389					14,389			
130	Shared Service	7450	TGS ST GALVESTON GENERAL	9210 Total									33,697					33,697	88.69%	46.4931%	13,895
131	Shared Service	7550	TGS ST PORT ARTHUR GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES							5,885					5,885			
132	Shared Service	7550	TGS ST PORT ARTHUR GENERAL	9210	9210304	A&G S&E CELLULAR PHONES							32,668					32,668			
133	Shared Service	7550	TGS ST PORT ARTHUR GENERAL	9210	9210308	A&G S&E TELE DATA							21,568					21,568			
134	Shared Service	7550	TGS ST PORT ARTHUR GENERAL	9210 Total									60,121					60,121	88.69%	46.4931%	24,791
135	Shared Service	7608	TGS WT DELL CITY	9210	9210303	A&G S&E TELE LOCAL LINES							379					379			
136	Shared Service	7608	TGS WT DELL CITY	9210	9210304	A&G S&E CELLULAR PHONES							483					483			
137	Shared Service	7608	TGS WT DELL CITY	9210	9210308	A&G S&E TELE DATA							461					461			
138	Shared Service	7608	TGS WT DELL CITY	9210 Total									1,323					1,323	88.69%	46.4931%	546
139	Shared Service	7635	TGS WT PERMIAN AREA GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES							3,742					3,742			
140	Shared Service	7635	TGS WT PERMIAN AREA GENERAL	9210	9210304	A&G S&E CELLULAR PHONES							18,733					18,733			
141	Shared Service	7635	TGS WT PERMIAN AREA GENERAL	9210	9210308	A&G S&E TELE DATA							33,419					33,419			
142	Shared Service	7635	TGS WT PERMIAN AREA GENERAL	9210 Total									55,894					55,894	88.69%	46.4931%	23,048
143	Shared Service	7650	TGS WT EL PASO GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES							1,623					1,623			
144	Shared Service	7650	TGS WT EL PASO GENERAL	9210	9210304	A&G S&E CELLULAR PHONES							163,671					163,671			
145	Shared Service	7650	TGS WT EL PASO GENERAL	9210 Total									165,294					165,294	88.69%	46.4931%	68,159
146	Shared Service	7700	TGS RGV GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES							8,458					8,458			
147	Shared Service	7700	TGS RGV GENERAL	9210	9210304	A&G S&E CELLULAR PHONES							94,507					94,507			
148	Shared Service	7700	TGS RGV GENERAL	9210	9210308	A&G S&E TELE DATA							3,191					3,191			
149	Shared Service	7700	TGS RGV GENERAL	9210 Total									106,156					106,156	88.69%	46.4931%	43,774
150	Shared Service	7800	TGS NT GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES							19,793					19,793			
151	Shared Service	7800	TGS NT GENERAL	9210	9210304	A&G S&E CELLULAR PHONES							36,042					36,042			
152	Shared Service	7800	TGS NT GENERAL	9210	9210308	A&G S&E TELE DATA							17,616					17,616			
153	Shared Service	7800	TGS NT GENERAL	9210 Total									73,450					73,450	88.69%	46.4931%	30,287
154	Shared Service	7801	TGS NT DISTRICT ADMIN	9210	9210303	A&G S&E TELE LOCAL LINES							25,457					25,457			
155	Shared Service	7801	TGS NT DISTRICT ADMIN	9210	9210304	A&G S&E CELLULAR PHONES							1,806					1,806			
156	Shared Service	7801	TGS NT DISTRICT ADMIN	9210	9210308	A&G S&E TELE DATA							3,879					3,879			
157	Shared Service	7801	TGS NT DISTRICT ADMIN	9210 Total									31,142					31,142	88.69%	46.4931%	12,841
158	Shared Service	7860	TGS BORGER GENERAL	9210	9210303	A&G S&E TELE LOCAL LINES							23,078					23,078			
159	Shared Service	7860	TGS BORGER GENERAL	9210	9210304	A&G S&E CELLULAR PHONES							11,297					11,297			
160	Shared Service	7860	TGS BORGER GENERAL	9210	9210308	A&G S&E TELE DATA							15,921					15,921			
161	Shared Service	7860	TGS BORGER GENERAL	9210 Total									50,296					50,296	88.69%	46.4931%	20,740
162																					
163				Grand Total			577,466	(6,924,897)	(23,176)	(11,715)	(2,698)	(850)	803,521	(21,793,189)	9,085,508	9,396,274	(2,549,340)	(11,443,095)			
164						O&M Expense Factor	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%			
165						Adjustment to TGS O&M	512,162	(6,141,777)	(20,555)	(10,390)	(2,393)	(754)	712,653	(19,328,649)	8,058,050	8,333,671	(2,261,041)	(10,149,023)			(4,718,595)
166																					
167						Allocation to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%			
168																					
						Adjustment to Service Area O&M	**238,120**	**(2,855,502)**	**(9,557)**	**(4,831)**	**(1,112)**	**(351)**	**331,334**	**(8,986,488)**	**3,746,437**	**3,874,582**	**(1,051,228)**	**(4,718,595)**			

MISCELLANEOUS ADJUSTMENTS
DISTRIGAS

LINE NO.	CATEGORY	TO COST CENT ER	TO COST CENTER DESCRIPTION	FERC ACCT	NATURAL ACCT	ACCT DESCRIPTION	Adjustment for Known and measurable change in Insurance premiums (a)	Adjustment to remove payroll related (Taxes and Benefits) activity that clears through labor attends. The adjustment for these accounts can be found on Schedule G-6. (b)	Adjustment to remove RGV service area specific costs (c)	Adjustment to remove Royalty expenses (d)	Exclude - Rule 7.514 - Legislative, Governmental, or electoral activity (e)	Exclude/Adjust out - Management decision not to request recovery. (g)	Include Equivalent Commercial Aifare (h)	Exclude/Adjust out- Rule 7.5414 Contributions, donations to charitable, religious, or other nonprofit organizations (i)			Distrigas Adjustment (i)	Grand Total (k)	DISTRIGAS FACTOR (l)	O&M EXPENSE FACTOR (m)	ALLOCATION TO SERVICE AREA (n)	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT (o)
1	OGS Corporate Allocated through Distrigas (1007)	1007	OKE ALLOCATIONS/DSTR	4081	4081995	A&G MISC DISTRIGAS ALLOC											-	-				
2			**Total Ferc Account**	**4081**			-	-	-	-	-	-	-	-	-	-	-	-	**25.01%**	**88.69%**	**46.4931%**	-

WKP G-9.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

MISCELLANEOUS ADJUSTMENTS
SHARED SERVICES

LINE NO.	CATEGORY	To Cc	Tocostcenter Description	FERC Account	Natural Account	Account Description	Adjustment for Known and measurable change in Insurance premiums	Adjustment to remove costs associated with Royalty fees	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 Stock Award Activity as the program ended	Telecom Reclass	Adjustment to Remove Payroll Related Taxes and Benefits	Adjustment to Included 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	Grand 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)	(m)	(n)	(o)	
3	OGS Corporate Allocated through Distrigas (1007)	1007	OKE ALLOCATIONS/DSTR	9302	9302995	A&G MISC DISTRIGAS ALLOC											(2,164,559)	(2,164,559)				
4			**Total Ferc Account**	**9302**			-	-	-	-	-	-	-	-	-	-	**(2,164,559)**	**(2,164,559)**	**25.01%**	**88.69%**	**46.4931%**	**(223,230)**
4	OGS Corporate Allocated through Distrigas (1007)	1007	OKE ALLOCATIONS/DSTR	9260	9260995	A&G EMPL BEN SERP DISTRIGAS ALLOC											(1,757,584)	(1,757,584)				
5	OGS Corporate Allocated through Distrigas (1007)	1007	OKE ALLOCATIONS/DSTR	9260	9260996	A&G EMPL BEN PENSION DISTRIGAS											-	-				
6	OGS Corporate Allocated through Distrigas (1007)	1007	OKE ALLOCATIONS/DSTR	9260	9260997	A&G EMPL BEN FAS 106 DISTRIGAS ALLOC											-	-				
7			**Total Ferc Account**	**9260**			-	-	-	-	-	-	-	-	-	-	**(1,757,584)**	**(1,757,584)**	**25.01%**	**88.69%**	**46.4931%**	**(181,259)**
7																						
8	**Grand Total Distrigas**						-	-	-	-	-	-	-	-	-	-	**(3,922,143)**	**(3,922,143)**				**(404,489)**
9																						
10						Distrigas Allocation Percent	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%	25.01%				
10						Corporate Adjustment Allocated to TGS	-	-	-	-	-	-	-	-	-	-	(980,928)	(980,928)				
11																						
12						O&M Expense Factor	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%	88.69%				
13						Adjustment to TGS O&M	-	-	-	-	-	-	-	-	-	-	(869,997)	(869,997)				
13																						
14						Allocation to Service Area	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%	46.4931%				
15																						
16						**Adjustment to Service Area O&M**	-	-	-	-	-	-	-	-	-	-	**(404,489)**	**(404,489)**				

Source: WKP G-9.b Shared Service Test Year OH- CGSA.xlsx
Source: WKP G-9.b.2 Misc Adjustments Distrigas.xlsx
Source: WKP G-9.b.3 Insurance Adjustment.xlsx

WKP G-9.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

MEAL AND HOTEL ADJUSTMENTS
DIRECT, SHARED SERVICES, DISTRIGAS

LINE NO.	DESCRIPTION	ACCT	REMOVAL OF SPOUSAL EXPENSE	REMOVAL OF MEALS OVER $25 PER PERSON	REMOVAL OF HOTEL OVER $150 PER NIGHT	REMOVAL OF ALCOHOL	TOTAL
			(a)	(b)	(c)	(d)	(e)
1	Transmission O & M - Mains Expenses	8560	$0	$0	$0	$0	$0
2	Maintenance of Mains	8630	0	0	0	0	0
3	Distr. Operations- General Supervision	8700	0	(20)	0	0	(20)
4	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0	0
5	Distr. Operations - Mains & Services	8740	0	(126)	0	0	(126)
6	Meas & Reg. Stat. Exp. - General	8750	0	0	0	0	0
7	Distr. Operations - Meter & House Reg. Exp.	8780	0	(5)	0	0	(5)
8	Distr. Operations - Other Expense	8800	0	(279)	0	0	(279)
9	Distr. Operations - Rents	8810	0	0	0	0	0
10	Distr. Maintenance - Mains	8870	0	(0)	0	0	(0.44)
11	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0	0
12	Distr. Maintenance- Cathodic Protection	8900	0	(45)	0	0	(45)
13	Customer Accounting - Supervision	9010	0	0	0	0	0
14	Customer Accounting	9030	0	0	0	0	0
15	Miscellaneous	9050	0	0	0	0	0
16	Customer Asst.- Misc. Expenses	9080	0	(185)	0	(4)	(189)
17	Demo/Sell- Misc. Expenses	9120	0	0	0	0	0
18	Admin & Gen - Office Supp & Exp	9210	0	(192)	0	0	(192)
19	Admin & Gen - Outside Services	9230	0	0	0	0	0
20	Admin & Gen - Injuries & Damages	9250	0	0	0	0	0
21	Admin & Gen - Employee Pensions & Benefits	9260	0	0	0	0	0
22	Admin & Gen - Regulatory Commission Expense	9280	0	0	0	0	0
23	Admin & Gen - Misc General	9302	0	(32)	0	0	(32)
24	Admin & Gen - Rents	9310	0	0	0	0	0
25	**Grand Total Direct**		$0	($885)	$0	($4)	**($888)**

LINE NO.	DESCRIPTION	ACCT	REMOVAL OF SPOUSAL EXPENSE	REMOVAL OF MEALS OVER $25 PER PERSON	REMOVAL OF HOTEL OVER $150 PER NIGHT	REMOVAL OF ALCOHOL	TOTAL	O&M EXPENSE FACTOR	ALLOCATION TO SERVICE AREA	ADJUSTMENT ALLOCATED TO SERVICE AREA BY FERC ACCT
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Transmission O & M - Mains Expenses	8560	$0	($10)	$0	$0	($10)	88.69%	46.49%	($4.14)
2	Transmission O & M - Mains Expenses Misc	8590	0	(10)	0	0	($10)	88.69%	46.49%	($4.14)
3	Maintenance of Mains	8630	0	0	0	0	0	88.69%	46.49%	0
4	Distr. Operations- General Supervision	8700	0	(508)	(953)	0	(1460)	88.69%	46.49%	(602)
5	Distr. Operations - Distribution Load Dispatch	8710	0	(1,000)	0	0	(1000)	88.69%	46.49%	(412)
6	Distr. Operations - Mains & Services	8740	0	0	0	0	0	88.69%	46.49%	0
7	Meas & Reg. Stat. Exp. - General	8750	0	0	0	0	0	88.69%	46.49%	0
8	Distr. Operations - Meter & House Reg. Exp.	8780	0	(0)	0	0	(0)	88.69%	46.49%	(0)
9	Distr. Operations - Other Expense	8800	0	(67)	0	0	(67)	88.69%	46.49%	(28)
10	Distr. Operations - Rents	8810	0	0	0	0	0	88.69%	46.49%	0
11	Distr. Maintenance - Mains	8870	0	(1)	0	0	(1)	88.69%	46.49%	(0)
12	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0	0	88.69%	46.49%	0
13	Distr. Maintenance- Cathodic Protection	8900	0	0	0	0	0	88.69%	46.49%	0

LINE NO.	DESCRIPTION	ACCT	REMOVAL OF SPOUSAL EXPENSE	REMOVAL OF MEALS OVER $25 PER PERSON	REMOVAL OF HOTEL OVER $150 PER NIGHT	REMOVAL OF ALCOHOL	TOTAL	O&M EXPENSE FACTOR	ALLOCATION TO SERVICE AREA	ADJUSTMENT ALLOCATED TO SERVICE AREA BY FERC ACCT
14	Customer Accounting - Supervision	9010	0	(725)	0	0	(725)	88.69%	46.49%	(299)
15	Customer Accounting	9030	0	(123)	0	0	(123)	88.69%	46.49%	(51)
16	Miscellaneous	9050	0	(15)	0	0	(15)	88.69%	46.49%	(6)
17	Customer Asst.- Misc. Expenses	9080	0	(463)	0	(84)	(547)	88.69%	46.49%	(226)
18	Demo/Sell- Misc. Expenses	9120	0	0	0	0	0	88.69%	46.49%	0
19	Admin & Gen - Office Supp & Exp	9210	0	(1,464)	(886)	(80)	(2430)	88.69%	46.49%	(1002)
20	Admin & Gen - Outside Services	9230	0	0	0	0	0	88.69%	46.49%	0
21	Admin & Gen - Injuries & Damages	9250	0	0	0	0	0	88.69%	46.49%	0
22	Admin & Gen - Employee Pensions & Benefits	9260	0	0	0	0	0	88.69%	46.49%	0
23	Admin & Gen - Regulatory Commission Expense	9280	0	0	0	0	0	88.69%	46.49%	0
24	Admin & Gen - Misc General	9302	0	0	0	0	0	88.69%	46.49%	0
25	Admin & Gen - Rents	9310	0	0	0	0	0	88.69%	46.49%	0
26	**Grand Total Shared Service**		$0	($4,387)	($1,839)	($164)	($6,390)	**88.69%**	**46.4931%**	**($2,635)**
27	O&M Expense Factor		88.69%	88.69%	88.69%	88.69%	88.69%			
26	Adjustment to TGS O&M		$0	($3,890)	($1,631)	($145)	($5,667)			
27	Allocation to Service Area		46.4931%	46.4931%	46.4931%	46.4931%	46.4931%			
	Adjustment to Service Area O&M		**$0**	**($1,809)**	**($758)**	**($68)**	**($2,635)**			

LINE NO.	DESCRIPTION	ACCT	REMOVAL OF SPOUSAL EXPENSE	REMOVAL OF MEALS OVER $25 PER PERSON	REMOVAL OF HOTEL OVER $150 PER NIGHT	REMOVAL OF ALCOHOL	TOTAL	DISTRIGAS FACTOR	O&M EXPENSE FACTOR	ALLOCATION TO SERVICE AREA	ADJUSTMENT ALLOCATED TO SERVICE AREA BY FERC ACCT
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
28	Admin & Gen - Misc General	9302	($625)	($61,918)	($38,289)	($16,225)	($117,057)				
29	**Grand Total Distrigas**		**($625)**	**($61,918)**	**($38,289)**	**($16,225)**	**($117,057)**	**25.01%**	**88.69%**	**46.4931%**	**($12,072)**
30	Distrigas Allocation Percent		25.01%	25.01%	25.01%	25.01%	25.01%				
31	Corporate Adjustment Allocated to TGS		($156)	($15,486)	($9,576)	($4,058)	($29,276)				
32	O&M Expense Factor		88.69%	88.69%	88.69%	88.69%	88.69%				
33	Adjustment to TGS O&M		($139)	($13,734)	($8,493)	($3,599)	($25,965)				
34	Allocation to Service Area		46.4931%	46.4931%	46.4931%	46.4931%	46.4931%				
35	**Adjustment to Service Area O&M**		**($64)**	**($6,386)**	**($3,949)**	**($1,673)**	**($12,072)**				

Source: WKP G-9.c Meal & Hotel Adjustments Direct SS and Distr(CONFIDENTIAL).xlsx

SCHEDULE G-10

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	(5,509)	(5,509)
21	Admin & Gen - Rents	9310	0	(73,824)	0	(73,824)
22	Totals		$0	($73,824)	($5,509)	($79,333)

WKP G-10.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

RENTS AND LEASES ADJUSTMENTS
SHARED SERVICES

LINE NO.	CATEGORY	ACCOUNT DESCRIPTION	FERC ACCT	ADUSTMENT FOR THE TERMINATED INFORMATION CENTER 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	88.69%	46.4931%	$0
2	Shared Service	Distr. Operations - Supervision and Engineering	8700	0	0	0	88.69%	46.4931%	0
3	Shared Service	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	88.69%	46.4931%	0
4	Shared Service	Distr. Operations - Mains & Services	8740	0	0	0	88.69%	46.4931%	0
5	Shared Service	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	88.69%	46.4931%	0
6	Shared Service	Distr. Operations - Other Expense	8800	0	0	0	88.69%	46.4931%	0
7	Shared Service	Distr. Operations - Rents	8810	0	0	0	88.69%	46.4931%	0
8	Shared Service	Distr. Maintenance - Mains	8870	0	0	0	88.69%	46.4931%	0
9	Shared Service	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	88.69%	46.4931%	0
10	Shared Service	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Ind.	8900	0	0	0	88.69%	46.4931%	0
11	Shared Service	Customer Accounting - Supervision	9010	0	0	0	88.69%	46.4931%	0
12	Shared Service	Customer Accounting - Customer Accounting	9030	0	0	0	88.69%	46.4931%	0
13	Shared Service	Customer Accounting - Miscellaneous	9050	0	0	0	88.69%	46.4931%	0
14	Shared Service	Customer Accounting - Customer Assistance Expense	9080	0	0	0	88.69%	46.4931%	0
15	Shared Service	Admin & Gen - Office Supp & Exp	9210	0	0	0	88.69%	46.4931%	0
16	Shared Service	Admin & Gen - Outside Services	9230	0	0	0	88.69%	46.4931%	0
17	Shared Service	Admin & Gen - Injuries & Damages	9250	0	0	0	88.69%	46.4931%	0
18	Shared Service	Admin & Gen - Employee Pensions & Benefits	9260	0	0	0	88.69%	46.4931%	0
19	Shared Service	Admin & Gen - General Advertising Expense	9301	0	0	0	88.69%	46.4931%	0
20	Shared Service	Admin & Gen - Misc General	9302	0	0	0	88.69%	46.4931%	0
21	Shared Service	Admin & Gen - Rents	9310	(266,675)	87,645	(179,030)	88.69%	46.4931%	(73,824)
22	Grand Total Shared Services			($266,675)	$87,645	($179,030)			($73,824)
23									
24			O&M Expense Factor	88.69%	88.69%	88.69%			
25			Adjustment to TGS O&M	($236,517)	$77,733	($158,784)			
26									
27			Allocation to Service Area	46.4931%	46.4931%	46.4931%			
28									
29			Adjustment to Service Area O&M	($109,964)	$36,141	($73,824)			

WKP G-10.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
	OGS Corporate Allocated through									
30	Distrigas (1007)	Admin & Gen - Misc General	9302	($53,418)	$0	($53,418)	25.01%	88.69%	46.4931%	($5,509)
31	Grand Total Distrigas			($53,418)	$0	($53,418)				($5,509)
32										
33			Distrigas Allocation Percent	25.01%	25.01%	25.01%				
34			Corporate Adjustment Allocated to TGS	($13,360)	$0	($13,360)				
35										
36			O&M Expense Factor	88.69%	88.69%	88.69%				
37			Adjustment to TGS O&M	($11,849)	$0	($11,849)				
38										
39			Allocation to Service Area	46.4931%	46.4931%	46.4931%				
40										
41			Adjustment to Service Area O&M	($5,509)	$0	($5,509)				

Source: WKP G-10.b.1 Rent Adjustment Distr & SS (CONFIDENTIAL).xlsx

SCHEDULE G-11

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

INTEREST ON CUSTOMER DEPOSITS

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
			(a)
1	Service Area Active Customer Deposits		$7,853,752
2	Interest Rate on Customer Deposits		1.92%
3	Annualized Interest on Customer Deposits		$150,792
4	Test Year Interest on Customer Deposits - Acct 4310	WKP G.a.2	117,153
5	Adjustment to Test Year Expense		$33,639

Source: SCH G-11 Customer Deposit Interest_ PUC Interest Rate for Deposits_CGSA.pdf

SCHEDULE G-12

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

UNCOLLECTIBLE EXPENSE

LINE NO.	DESCRIPTION	REFERENCE		AMOUNT
		(a)	(b)	(c)
1	As Adjusted Base (Non-Gas) Revenue	G-2		$96,912,395
2	As Adjusted Transportation, Fees & Other Utility Revenue	G-3		12,091,812
3	Total Adjusted Base and Other Revenue (Note 2)			$109,004,207
4	Uncollectible Expense Ratio (Note 1)			0.005373
5	Adjusted Uncollectible Expense			$585,680
6	Test Year Uncollectible Expense - Acct 9040			527,099
7	Adjustment to Test Year Expense			$58,580

	Note 1: Calculation of Uncollectible Ratio	Base Revenue Write Offs	Base Revenue	Uncollectible Ratio
8	Twelve Months Ended June 2017	$416,035	$96,140,437	0.004327
9	Twelve Months Ended June 2018	587,229	101,416,637	0.005790
10	Twelve Months Ended June 2019	611,816	103,050,949	0.005937
11	Average	$538,360	$100,202,674	0.005373

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 expense above is calculated based only on base revenue.

Source: SCH G-12 CGSA Uncollectibles by Svc Area.xlsx

Schedule G-13

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	July 2015 - June 2016		$341,434	$36,497	$68,171	$446,102
2	July 2016 - June 2017		246,537	53,693	155,591	455,821
3	July 2017 - June 2018		161,942	7,286	126,799	296,027
4	July 2018 - June 2019		163,342	7,871	398,256	569,469
5	Total		$913,255	$105,347	$748,817	$1,767,419
6	Average Claims for TGS Division		$228,314	$26,337	$187,204	$441,855
7	Per Book	Acct 9250	324,606	12,302	407,766	744,674
8	Adjustment					($302,819)
9	Allocation to Service Area					46.4931%
10	Adjustment to Employee Injury, Auto, and General Liability Claims					($140,790)
11	O&M Expense Factor					88.69%
12	Adjustment to Employee Injury, Auto, and General Liability Claims with O&M factor applied					($124,868)

Source: SCH G-13 Inj and Dam per book (CONFIDENTIAL) - CGSA.xlsx

WKP G-13.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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;
and Impairment Income Benefits (IIBs) financial 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: July 1, 2015 through June 30, 2019

Employee Injuries	**2019**	**2018**	**2017**	**2016**	**2015**
	$ Paid	$ Paid	$ Paid	$ Paid	
January	$23,494	$8,344	$12,654	$23,055	
February	11,302	17,235	14,300	27,506	
March	37,662	13,632	15,363	39,371	
April	15,093	15,510	19,909	19,861	
May	13,294	16,055	19,002	20,893	
June	4,827	12,769	17,261	25,713	
July		9,165	8,477	28,776	29,126
August		5,266	9,428	35,701	32,358
September		10,544	7,860	24,006	33,874
October		8,216	30,445	42,037	19,679
November		12,538	13,942	6,171	33,143
December		11,940	8,247	11,357	36,857
Sub Total	$163,342	$161,942	$246,537	$341,434	
4 Year Average					
July - June Test Year			**$228,314**		

Auto Accidents
Period Reporting: July 1, 2015 through June 30, 2019

Auto Accidents	**2019**	**2018**	**2017**	**2016**	**2015**
	$ Paid	$ Paid	$ Paid	$ Paid	
January	$0	$0	$3,009	$111	
February	1,367	0	509	18,366	
March	0	0	27	117	
April	0	0	40,664	2,114	
May	0	0	75	2,957	
June	0	0	1,957	5,962	
July	2,900	0	561	0.00	4,068
August		6,504	0.00	317	718
September		0	4,277	2,507	0
October		0	1,415	1,713	1,031
November		0	0.00	0.00	1,054
December		0	1,033	2,914	0
Sub Total	$7,871	$7,286	$53,693	$36,497	
4 Year Average					
July - June Test Year			**$26,337**		

WKP G-13.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

INJURIES AND DAMAGES

	General Liability Period Reporting: July 1, 2015 through June 30, 2019				
General Liability	**2019**	**2018**	**2017**	**2016**	**2015**
	$ Paid	$ Paid	$ Paid	$ Paid	
January	$14,691	$12,940	$6,521	$19,306	
February	16,019	36,025	11,514	5,543	
March	9,186	20,650	4,752	1,834	
April	49,505	9,470	10,044	9,081	
May	5,274	3,588	4,773	8,681	
June	72,806	1,300	27,521	1,305	
July	52,289	5,809	19,533	18,112	1,450
August		63,567	6,104	32,531	4,207
September		5,932	2,015	17,400	2,778
October		86,114	13,628	7,007	773
November		48,366	886	2,694	3,000
December		20,987	662	12,722	10,213
Sub Total	$398,256	$126,799	$155,591	$68,171	
4 Year Average July - June Test Year			**$187,204**		

SCHEDULE G-14

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$23,611	$0	$0	$0	$23,611
2	Advertising - Misc. Adm & Gen. Expense	WKP G.a.1	9301	10,076	0	0	0	10,076
3	Distrigas Allocated Advertising	WKP G.a.2	9302	3,423	0	0	0	3,423
4	Total Adjusted Advertising Expense			$37,109	$0	$0	$0	$37,109

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			$126,050,873
7	Normalized CCF	G-2		155,480,633	
8	Test Year Cost of Gas Revenue	G-2	$75,042,680		
9	Test Year CCF	G-2	162,697,883		
10	Effective Rate		0.46123944	0.461239440	
11	Normalized Cost of Gas Revenue			$71,713,800	$71,713,800
12	Total Revenue				$197,764,673
13	Allowed Rate				0.50%
14	Allowable Advertising				$988,823

O&M Expense Factor	88.69%
Allocation to Service Area	46.4931%
Distrigas Allocation Factor	25.0100%

Source: WKP G-14 Advertising Direct_CGSA.xlsx
Source: WKP G.a.2.a2 Corporate Costs Allocated on a Causal Basis and Through Distrigas-(CONFIDENTIAL) - CGSA

SCHEDULE G-15

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

DEPRECIATION AND AMORTIZATION EXPENSE

LINE NO.	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	$2,250	$0	$0	$2,250
2	(301) Organization - OPC	87	0	0	87
3	(302) Franchises & Consents	0	0	0	0
4	(303) Misc. Intangible	30,027	0	0	30,027
5	(303) Misc. Intangible - OPC	0	0	0	0
6	Total Intangible Plant	$32,365	$0	$0	$32,365
	GATHERING AND TRANSMISSION PLANT				
7	(325) Land & Land Rights	$0	$0	$0	$0
8	(327) Field Comprss Station Strucutres	0	0	0	0
9	(328) Field Meas/Reg Station Structures	0	0	0	0
10	(329) Other Structures	0	0	0	0
11	(332) Field Lines	0	0	0	0
12	(333) Field Compressor Station Equip	0	0	0	0
13	(334) Field Meas/Reg Station Equipment	0	0	0	0
14	(336) Purification Equipment	0	0	0	0
15	(337) Other Equip	0	0	0	0
16	(365) Land & Land Rights	0	0	0	0
17	(365.1) Land - OPC	0	0	0	0
18	(365.2) Rights of Way - OPC	32	0	0	32
19	(366) Meas/Reg Station Structures	0	0	0	0
20	(366.1) Compressor Station Stru - OPC	95	0	0	95
21	(367) Mains	92,986	0	0	92,986
22	(367) Mains - OPC	120,923	0	0	120,923
23	(368) Compressor Station Equip	0	0	0	0
24	(369) Measure/Reg. Station Equipment	26,490	0	0	26,490
25	(369) Measuring & Regulating - OPC	2,425	0	0	2,425
26	(369.1) Measuring Station Equip - OPC	21,240	0	0	21,240
27	(371) Other Equipment	0	0	0	0
28	(371) Other Transmission Eq - OPC	1,201	0	0	1,201
29	Total Gathering and Transmission Plant	$265,391	$0	$0	$265,391

SCHEDULE G-15

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

DEPRECIATION AND AMORTIZATION EXPENSE

LINE NO.	DESCRIPTION	DIRECT DEPR & AMORT EXP	TGS DIVISION ALLOCATED DEPR & AMORT EXP	CORPORATED ALLOCATED DEPR & AMORT EXP	TOTAL DEPR & AMORT EXP
		(a)	(b)	(c)	(d)
	DISTRIBUTION PLANT				
30	(374) Land & Land Rights	$0	$0	$0	$0
31	(375.1) Structures & Improvements	750	0	0	750
32	(375.2) Other Distr Systems Struct	386	0	0	386
33	(376) Mains	7,674,509	0	0	7,674,509
34	(377) Compressor Station Equipment	0	0	0	0
35	(378) Meas. & Reg. Station - General	310,750	0	0	310,750
36	(379) Meas. & Reg. Station - C.G.	45,645	0	0	45,645
37	(380) Services	4,742,152	0	0	4,742,152
38	(381) Meters	2,639,514	0	0	2,639,514
39	(382) Meter Installations	0	0	0	0
40	(383) House Regulators	232,452	0	0	232,452
41	(385) Indust. Meas. & Reg. Stat. Equipment	298,889	0	0	298,889
42	(386) Other Property on Customer Premises	(1,701)	0	0	(1,701)
43	(387) Meas. & Reg. Stat. Equipment	0	0	0	0
44	Total Distribution Plant	$15,943,347	$0	$0	$15,943,347
	GENERAL PLANT				
45	(389) Land & Land Rights	$0	$0	$0	0
46	(389.1) Land & Land Rights	0	0	0	0
47	(390) Structures & Improvements	0	0	0	0
48	(390.1) Structures & Improvements	113,988	35,909	487	150,384
49	(390.2) Leasehold Improvements	285,138	0	82,124	367,262
50	(391) Office Furniture & Equipment	0	0	0	0
51	(391.1) Computer & Equipment	64,154	13,581	2,251,613	2,329,348
52	(391.1) Office Furniture & Fixt - OPC	2,243	0	0	2,243
53	(391.9) Computer & Equipment	268,961	179,609	0	448,570
54	(392) Transportation Equipment	0	0	0	0
55	(393) Stores Equipment	588	0	0	588
56	(394) Tools, Shop & Garage	516,924	622	0	517,546
57	(394.1) Tools, Shop & Garage	8,278	0	0	8,278
58	(394.1) Tools - OPC	32	0	0	32
59	(395) CNG Equipment	0	0	0	0
60	(396) Major Work Equipment	0	0	0	0
61	(397) Communication Equipment	1,242,991	33,506	596	1,277,093
62	(398) Miscellaneous General Plant	8,691	0	0	8,691
63	Total General Plant	$2,511,988	$263,227	$2,334,819	$5,110,034
64	Total	$18,753,091	$263,227	$2,334,819	$21,351,137
65	Total Annualized Depreciation & Amortization Expense	$18,753,091	$263,227	$2,334,819	$21,351,137
66	Test Year Depreciation & Amortization Expense Accts 403 & 404	16,455,342	295,235	2,052,774	18,803,351
67	Adjustment to Test Year	$2,297,749	($32,008)	$282,045	$2,547,785

WKP G-15.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

DEPRECIATION AND AMORTIZATION EXPENSE - SERVICE AREA DIRECT

LINE NO.	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 DEPR & AMORT EXPENSE
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	INTANGIBLE PLANT									
1	(301) Organization	$56,257	$0	$0	$0	$0	$0	$56,257	4.0000%	$2,250
2	(301) Organization - OPC	1,307	0	0	0	0	0	1,307	6.6700%	$87
3	(302) Franchises & Consents	393,474	0	0	0	(393,474)	0	0	4.0200%	0
4	(303) Misc. Intangible	739,593	0	0	0	0	0	739,593	4.0600%	30,027
5	(303) Misc. Intangible- OPC	14,336	0	0	0	(14,336)	0	0	0.0000%	0
6	Total Intangible Plant	$1,204,966	$0	$0	$0	($407,810)	$0	$797,156		$32,365
	GATHERING AND TRANSMISSION PLANT									
7	(325) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0
8	(327) Field Comprss Station Strucutres	0	0	0	0	0	0	0	0.0000%	0
9	(328) Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0.0000%	0
10	(329) Other Structures	0	0	0	0	0	0	0	0.0000%	0
11	(332) Field Lines	0	0	0	0	0	0	0	0.0000%	0
12	(333) Field Compressor Station Equip	0	0	0	0	0	0	0	0.0000%	0
13	(334) Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0.0000%	0
14	(336) Purification Equipment	0	0	0	0	0	0	0	0.0000%	0
15	(337) Other Equip	0	0	0	0	0	0	0	0.0000%	0
16	(365) Land & Land Rights	0	0	0	0	0	0	0	0.0000%	0
17	(365.1) Land - OPC	89,637	0	(89,637)	0	0	0	0	0.0000%	0
18	(365.2) Rights of Way - OPC	2,446	0	0	0	0	0	2,446	1.3000%	32
19	(366) Meas/Reg Station Structures	0	0	0	0	0	0	0	0.0000%	0
20	(366.1) Compressor Station Stru - OPC	2,346	0	0	0	0	0	2,346	4.0400%	95
21	(367) Mains	3,986,195	1,327,284	0	0	0	0	5,313,478	1.7500%	92,986
22	(367) Mains - OPC	6,909,861	0	0	0	0	0	6,909,861	1.7500%	120,923
23	(368) Compressor Station Equip	0	0	0	0	0	0	0	0.0000%	0
24	(369) Measure/Reg. Station Equipment	211,577	1,235,959	0	0	0	0	1,447,536	1.8300%	26,490
25	(369) Measuring & Regulating - OPC	132,499	0	0	0	0	0	132,499	1.8300%	2,425
26	(369.1) Measuring Station Equip - OPC	810,700	0	0	0	0	0	810,700	2.6200%	21,240
27	(371) Other Equipment	0	0	0	0	0	0	0	0.0000%	0
28	(371) Other Transmission Eq - OPC	45,840	0	0	0	0	0	45,840	2.6200%	1,201
29	Total Gathering and Transmission Plant	$12,191,099	$2,563,242	($89,637)	$0	$0	$0	$14,618,865		$265,391
	DISTRIBUTION PLANT									
30	(374) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0
31	(374.1) Land & Land Rights	19,503	5,715,287	(5,734,790)	0	0	0	0	0.0000%	0
32	(374.2) Land & Land Rights	95,672	0	0	0	0	0	95,672	0.0000%	0
33	(375.1) Structures & Improvements	44,795	(916)	0	0	-	0	43,879	1.7100%	750
34	(375.2) Other Distr Systems Struct	4,141	12,063	0	0	0	0	16,204	2.3800%	386
35	(376) Mains	264,610,649	49,421,260	0	0	0	15	314,031,924	1.8800%	5,903,800
36	(376.9) Mains - Cathodic Protection Anodes	26,374,130	186,496	0	0	0	0	26,560,625	6.6667%	1,770,708
37	(377) Compressor Station Equipment	0	0	0	0	0	0	0	0.0000%	0
38	(378) Meas. & Reg. Station - General	10,468,864	4,021,774	0	0	0	167,383	14,658,021	2.1200%	310,750
39	(379) Meas. & Reg. Station - C.G.	2,577,593	113,443	0	0	0	9,878	2,700,913	1.6900%	45,645
40	(380) Services	180,146,234	5,478,258	0	0	0	342,264	185,966,756	2.5500%	4,742,152
41	(381) Meters	64,070,877	1,263,031	0	0	0	607	65,334,516	4.0400%	2,639,514

WKP G-15.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

DEPRECIATION AND AMORTIZATION EXPENSE - SERVICE AREA DIRECT

LINE NO.	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 DEPR & AMORT EXPENSE
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
42	(382) Meter Installations	0	6,007	0	0	(4,764)	(143)	1,100	0.0000%	0
43	(383) House Regulators	8,977,527	135,976	0	0	0	2,280	9,115,782	2.5500%	232,452
44	(385) Indust. Meas. & Reg. Stat. Equipment	12,819,751	1,075,889	0	0	0	6,168	13,901,808	2.1500%	298,889
45	(386) Other Property on Customer Premises	1,063,249	0	0	0	0	0	1,063,249	-0.1600%	(1,701)
46	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	1.9500%	0
47	Total Distribution Plant	$571,272,984	$67,428,568	($5,734,790)	$0	($4,764)	$528,452	$633,490,450		$15,943,347
	GENERAL PLANT									
48	(389) Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0
49	(389.1) Land & Land Rights	48,883	0	(48,883)	0	0	0	0	0.0000%	0
50	(390) Structures & Improvements	0	0	0	0	0	0	0	0.0000%	0
51	(390.1) Structures & Improvements	4,403,176	230,497	0	0	0	0	4,633,672	2.4600%	113,988
52	(390.2) Leasehold Improvements	1,214,164	701,474	0	0	0	0	1,915,638	14.8848%	285,138
53	(391) Office Furniture & Equipment	0	0	0	0	0	0	0	6.6667%	0
54	(391.1) Office Furniture & Equipment	962,315	0	0	0	0	0	962,315	6.6667%	64,154
55	(391.1) Office Furniture & Fixt - OPC	14,671	18,970	0	0	0	0	33,641	6.6667%	2,243
56	(391.9) Computer & Equipment	1,863,758	18,970	0	0	0	0	1,882,727	14.2857%	268,961
57	(392) Transportation Equipment	12,982,452	1,788,001	0	(14,770,453)	0	0	0	8.4900%	0
58	(393) Stores Equipment	8,809	0	0	0	0	0	8,809	6.6700%	588
59	(394) Tools, Shop & Garage	6,825,064	928,792	0	0	0	0	7,753,856	6.6667%	516,924
60	(394.1) Tools, Shop & Garage	105,228	18,940	0	0	0	0	124,168	6.6667%	8,278
61	(394.1) Tools - OPC	483	0	0	0	0	0	483	6.6667%	32
62	(395) CNG Equipment	0	0	0	0	0	0	0	0.0000%	0
63	(396) Major Work Equipment	1,529,033	430,811	0	(1,959,844)	0	0	0	5.4600%	0
64	(397) Communication Equipment	18,099,151	545,345	0	0	0	375	18,644,870	6.6667%	1,242,991
65	(398) Miscellaneous General Plant	130,360	0	0	0	0	0	130,360	6.6667%	8,691
66	Total General Plant	$48,187,546	$4,681,800	($48,883)	($16,730,297)	$0	$375	$36,090,540		$2,511,988
67	Total Plant in Service	$632,856,596	$74,673,610	($5,873,310)	($16,730,297)	($412,574)	$528,827	$684,997,012		$18,753,091
68	Total Annualized Depreciation & Amortization Expense									$18,753,091
69	Test Year Depreciation & Amortization Expense (Accts. 403 & 404)									16,455,342
70	Adjustment to Test Year									$2,297,749

	Note: Depreciation Related to Transportation Work Equipment:	Vehicles (392)	Work Equip (396)	Total	
71	Plant in Service + CCNC	$13,548,867	$1,560,721	$15,109,588	
72	Less Fully Depreciated Plant	0	0	0	
73	Net Depreciable Plant	$13,548,867	$1,560,721	$15,109,588	
74	Depreciation Rate	8.490%	5.460%		
75	Proforma Depreciation Expense	$1,150,299	$85,215	$1,235,514	(to Schedule G-19)

WKP G-15.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

FULLY DEPRECIATED PLANT - SERVICE AREA DIRECT

LINE NO.	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	$56,257	($43,615)	$12,642	$0
2	(301) Organization - OPC	$1,307	($726)	$581	0
3	(302) Franchises & Consents	393,474	(394,901)	(1,427)	(393,474)
4	(303) Misc. Intangible	739,593	(723,661)	15,932	0
5	(303) Misc. Intangible - OPC	14,336	(14,336)	0	(14,336)
6	Total Intangible Plant	$1,204,966	($1,177,239)	$27,727	($407,810)
	GATHERING AND TRANSMISSION PLANT				
7	(325) Land & Land Rights	$0	$0	$0	$0
8	(327) Field Comprss Station Strucutres	0	0	0	0
9	(328) Field Meas/Reg Station Structures	0	0	0	0
10	(329) Other Structures	0	0	0	0
11	(332) Field Lines	0	0	0	0
12	(333) Field Compressor Station Equip	0	0	0	0
13	(334) Field Meas/Reg Station Equipment	0	0	0	0
14	(336) Purification Equipment	0	0	0	0
15	(337) Other Equip	0	0	0	0
16	(365) Land & Land Rights	0	0	0	0
17	(365.1) Land - OPC	89,637	0	89,637	0
18	(365.2) Rights of Way - OPC	2,446	(2,124)	322	0
19	(366) Meas/Reg Station Structures	0	0	0	0
20	(366.1) Compressor Station Stru - OPC	2,346	(2,346)	0	0
21	(367) Mains	5,459,058	(1,610,512)	3,848,546	0
22	(367) Mains - OPC	6,909,861	(2,327,213)	4,582,648	0
23	(368) Compressor Station Equip	0	0	0	0
24	(369) Measure/Reg. Station Equipment	1,458,065	(67,538)	1,390,527	0
25	(369) Measuring & Regulating - OPC	132,499	(63,476)	69,023	0
26	(369.1) Measuring Station Equip - OPC	810,700	(537,229)	273,471	0
27	(371) Other Equipment	0	(11,056)	(11,056)	0
28	(371) Other Transmission Eq - OPC	45,840	0	45,840	0
29	Total Gathering and Transmission Plant	$14,910,451	($4,621,493)	$10,288,957	$0
	DISTRIBUTION PLANT				
30	(374) Land & Land Rights	$0	($255)	($255)	$0
31	(374.1) Land & Land Rights	19,503	0	19,503	0
32	(374.2) Land & Land Rights	95,672	(9,440)	86,233	0
33	(375) Structures & Improvements	48,935	9,965	58,900	0
34	(376) Mains	336,823,297	(76,774,051)	260,049,246	0
35	(377) Compressor Station Equipment	0	0	0	0
36	(378) Meas. & Reg. Station - General	13,124,532	(2,703,290)	10,421,242	0
37	(379) Meas. & Reg. Station - C.G.	2,691,033	(685,407)	2,005,627	0
38	(380) Services	179,315,795	(36,942,790)	142,373,005	0
39	(381) Meters	64,547,861	(24,368,018)	40,179,843	0
40	(382) Meter Installations	4,764	(10,137)	(5,373)	(4,764)
41	(383) House Regulators	9,035,151	(3,930,542)	5,104,609	0
42	(385) Indust. Meas. & Reg. Stat. Equipment	13,642,791	(4,332,235)	9,310,557	0
43	(386) Other Property on Customer Premises	1,063,249	(1,056,480)	6,769	0

WKP G-15.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

FULLY DEPRECIATED PLANT - SERVICE AREA DIRECT

LINE NO.	DESCRIPTION	DIRECT AS ADJUSTED PLANT 1010 & 1060	DIRECT AS ADJUSTED RESERVES 1080100 & 1110	NET PLANT AS ADJUSTED	FULLY DEPRECIATED PLANT
		(a)	(b)	(c)	(d)
44	(387) Meas. & Reg. Stat. Equipment	0	0	0	0
45	Total Distribution Plant	$620,412,584	($150,802,678)	$469,609,906	($4,764)
	GENERAL PLANT				
46	(389) Land & Land Rights	$0	$3,573	$3,573	$0
47	(389.1) Land & Land Rights	48,883	$0	48,883	0
48	(390) Structures & Improvements	0	0	0	0
49	(390.1) Structures & Improvements	4,554,870	(1,341,909)	3,212,962	0
50	(390.2) Leasehold Improvements	1,306,050	(961,505)	344,545	0
51	(391) Office Furniture & Equipment	0	0	0	0
52	(391.1) Office Furniture & Equipment	967,544	(499,178)	468,366	0
53	(391.1) Office Furniture & Fixt (OPC)	14,671	(14,671)	-	0
54	(391.9) Computer & Equipment	1,810,520	(1,576,132)	234,388	0
55	(392) Transportation Equipment	13,548,867	(4,453,397)	9,095,471	0
56	(393) Stores Equipment	8,809	(7,854)	955	0
57	(394) Tools, Shop & Garage	6,968,643	(2,539,633)	4,429,009	0
58	(394.1) Tools, Shop & Garage	60,552	0	60,552	0
59	(394.1) Tools (OPC)	483	(483)	0	0
60	(395) CNG Equipment	0	37,480	37,480	0
61	(396) Major Work Equipment	1,560,721	(817,467)	743,254	0
62	(397) Communication Equipment	18,519,235	(7,238,689)	11,280,546	0
63	(398) Miscellaneous General Plant	130,360	(77,989)	52,371	0
64	Total General Plant	$49,500,209	($19,487,854)	$30,012,355	$0
65	Total Orig Cost Plant in Service	$686,028,210	($176,089,264)	$509,938,946	($412,574)

WKP G-15.b.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

DEPRECIATION AND AMORTIZATION EXPENSE - TGS DIVISION

LINE NO.	DESCRIPTION	TGS DIVISION AS ADJUSTED ACCT 1010 PLANT (WKP C.b)	TGS DIVISION AS ADJUSTED ACCT 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		$0
2	(302) Franchises & Consents	0	0	0	0	0.0000%	0		0
3	(303) Misc. Intangible	0	0	0	0	0.0000%	0		0
4	Total Intangible Plant	$0	$0	$0	$0		$0		$0
	GATHERING AND TRANSMISSION PLANT								
5	(325) Land & Land Rights	$0	$0	$0	$0	0.0000%	$0		$0
6	(327) Field Comprss Station Strucutres	0	0	0	0	0.0000%	0		0
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0.0000%	0		0
8	(329) Other Structures	0	0	0	0	0.0000%	0		0
9	(332) Field Lines	0	0	0	0	0.0000%	0		0
10	(333) Field Compressor Station Equip	0	0	0	0	0.0000%	0		0
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0.0000%	0		0
12	(336) Purification Equipment	0	0	0	0	0.0000%	0		0
13	(337) Other Equip	0	0	0	0	0.0000%	0		0
14	(365) Land & Land Rights	0	0	0	0	0.0000%	0		0
15	(366) Meas/Reg Station Structures	0	0	0	0	0.0000%	0		0
16	(367) Mains	0	0	0	0	0.0000%	0		0
17	(368) Compressor Station Equip	0	0	0	0	0.0000%	0		0
18	(369) Measure/Reg. Station Equipment	0	0	0	0	0.0000%	0		0
19	(371) Other Equipment	0	0	0	0	0.0000%	0		0
20	Total Gathering and Transmission Plant	$0	$0	$0	$0		$0		$0
	DISTRIBUTION PLANT								
21	(374) Land & Land Rights	$0	$0	$0	$0	0.0000%	$0		$0
22	(375.1) Structures & Improvements	0	0	0	0	0.0000%	0		0
23	(376) Mains	0	0	0	0	0.0000%	0		0
24	(377) Compressor Station Equipment	0	0	0	0	0.0000%	0		0
25	(378) Meas. & Reg. Station - General	0	0	0	0	0.0000%	0		0
26	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0.0000%	0		0
27	(380) Services	0	0	0	0	0.0000%	0		0
28	(381) Meters	0	0	0	0	0.0000%	0		0
29	(382) Meter Installations	0	0	0	0	0.0000%	0		0
30	(383) House Regulators	0	0	0	0	0.0000%	0		0
31	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0		0
32	(386) Other Property on Customer Premises	0	0	0	0	0.0000%	0		0
33	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0		0
34	Total Distribution Plant	$0	$0	$0	$0		$0		$0
	GENERAL PLANT								
35	(389) Land & Land Rights	$0	$527,777	$0	$527,777	0.0000%	$0	46.4931%	$0
36	(390.1) Structures & Improvements	73,670	2,908,374	0	2,982,044	2.5900%	77,235	46.4931%	35,909
37	(390.2) Leasehold Equipment	106,600	0	(106,600)	0	17.3913%	0	46.4931%	0
38	(391.1) Office Furniture & Fixtures	438,158	0	0	438,158	6.6667%	29,211	46.4931%	13,581
39	(391.2) Data Processing Equipment	0	0	0	0	0.0000%	0	46.4931%	0
40	(391.3) Office Machines	0	0	0	0	0.0000%	0	46.4931%	0
41	(391.4) Audio Visual Equipment	0	0	0	0	0.0000%	0	46.4931%	0
42	(391.6) Purchased Software	0	0	0	0	0.0000%	0	46.4931%	0
43	(391.9) Computer & Equipment	2,704,198	0	0	2,704,198	14.2857%	386,314	46.4931%	179,609
44	(392.6) Aircraft	0	0	0	0	0.0000%	0	46.4931%	0
45	(394) Tools	20,066	0	0	20,066	6.6667%	1,338	46.4931%	622
46	(394.2) Shop Equipment	0	0	0	0	0.0000%	0	46.4931%	0
47	(397) Communication Equipment	1,080,989	0	0	1,080,989	6.6667%	72,066	46.4931%	33,506
48	(398) Miscellaneous General Plant	0	0	0	0	6.6667%	0	46.4931%	0
49	Total General Plant	$4,423,681	$3,436,151	($106,600)	$7,753,233		$566,163		$263,227
									0
50	Total Plant in Service	$4,423,681	$3,436,151	($106,600)	$7,753,233		$566,163		$263,227
51	Total Annualized Depreciation & Amortization Expense						$566,163	46.4931%	$263,227
52	Test Year Depreciation & Amortization Expense Accts 403 & 404						635,008	46.4931%	295,235
53	Adjustment to Test Year						($68,845)	46.4931%	($32,008)

WKP G-15.b.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

FULLY DEPRECIATED PLANT - TGS DIVISION

LINE NO.	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	Total Intangible Plant	$0	$0	$0	$0
	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	0	0	0	0
17	(368) Compressor Station Equip	0	0	0	0
18	(369) Measure/Reg. Station Equipment	0	0	0	0
19	(371) Other Equipment	0	0	0	0
20	Total Gathering and Transmission Plant	$0	$0	$0	$0
	DISTRIBUTION PLANT				
21	(374) Land & Land Rights	$0	$0	$0	$0
22	(375.1) Structures & Improvements	0	0	0	0
23	(376) Mains	0	0	0	0
24	(377) Compressor Station Equipment	0	0	0	0
25	(378) Meas. & Reg. Station - General	0	0	0	0
26	(379) Meas. & Reg. Station - C.G.	0	0	0	0
27	(380) Services	0	0	0	0
28	(381) Meters	0	0	0	0
29	(382) Meter Installations	0	0	0	0
30	(383) House Regulators	0	0	0	0
31	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0
32	(386) Other Property on Customer Premises	0	0	0	0
33	(387) Meas. & Reg. Stat. Equipment	0	0	0	0
34	Total Distribution Plant	$0	$0	$0	$0
	GENERAL PLANT				
35	(389) Land & Land Rights	$527,777	$0	$527,777	$0
36	(390.1) Structures & Improvements	2,982,044	(12,323)	2,969,721	0
37	(390.2) Leasehold Equipment	106,600	(107,734)	(1,134)	(106,600)
38	(391.1) Office Furniture & Fixtures	438,158	(276,377)	161,781	0
39	(391.2) Data Processing Equipment	0	0	$0	0
40	(391.3) Office Machines	0	0	0	0
41	(391.4) Audio Visual Equipment	0	0	0	0
42	(391.6) Purchased Software	-	0	-	0
43	(391.9) Computer & Equipment	2,704,198	(1,906,992)	$797,206	0
44	(392.6) Aircraft	0	0	0	0
45	(394) Tools	20,066	(9,009)	11,058	0
46	(394.2) Shop Equipment	0	0	0	0
47	(397) Communication Equipment	1,080,989	(652,579)	$428,410	0
48	(398) Miscellaneous General Plant	0	0	0	0
49	Total General Plant	$7,859,832	($2,965,014)	$4,894,818	($106,600)
50	Total Orig Cost Plant in Service	$7,859,832	($2,965,014)	$4,894,818	($106,600)

WKP G-15.c.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

DEPRECIATION AND AMORTIZATION EXPENSE - CORPORATE

LINE NO.	DESCRIPTION	CORPORATE AS ADJUSTED ALLOCATED TO TGS Acct 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	Total Intangible Plant	$0	$0	$0	$0		$0		$0
	GATHERING AND TRANSMISSION PLANT								
5	(325) Land & Land Rights	$0	$0	$0	$0	0.0000%	$0		
6	(327) Field Comprss Station Strucutres	0	0	0	0	0.0000%	0		
7	(328) Field Meas/Reg Station Structures	0	0	0	0	0.0000%	0		
8	(329) Other Structures	0	0	0	0	0.0000%	0		
9	(332) Field Lines	0	0	0	0	0.0000%	0		
10	(333) Field Compressor Station Equip	0	0	0	0	0.0000%	0		
11	(334) Field Meas/Reg Station Equipment	0	0	0	0	0.0000%	0		
12	(336) Purification Equipment	0	0	0	0	0.0000%	0		
13	(337) Other Equip	0	0	0	0	0.0000%	0		
14	(365) Land & Land Rights	0	0	0	0	0.0000%	0		
15	(366) Meas/Reg Station Structures	0	0	0	0	0.0000%	0		
16	(367) Mains	0	0	0	0	0.0000%	0		
17	(368) Compressor Station Equip	0	0	0	0	0.0000%	0		
18	(369) Measure/Reg. Station Equipment	0	0	0	0	0.0000%	0		
19	(371) Other Equipment	0	0	0	0	0.0000%	0		
20	Total Gathering and Transmission Plant	$0	$0	$0	$0		$0		$0
	DISTRIBUTION PLANT								
21	(374) Land & Land Rights	$0	$0	$0	$0	0.0000%	$0		
22	(375.1) Structures & Improvements	0	0	0	0	0.0000%	0		
23	(376) Mains	0	0	0	0	0.0000%	0		
24	(377) Compressor Station Equipment	0	0	0	0	0.0000%	0		
25	(378) Meas. & Reg. Station - General	0	0	0	0	0.0000%	0		
26	(379) Meas. & Reg. Station - C.G.	0	0	0	0	0.0000%	0		
27	(380) Services	0	0	0	0	0.0000%	0		
28	(381) Meters	0	0	0	0	0.0000%	0		
29	(382) Meter Installations	0	0	0	0	0.0000%	0		
30	(383) House Regulators	0	0	0	0	0.0000%	0		

WKP G-15.c.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

DEPRECIATION AND AMORTIZATION EXPENSE - CORPORATE

LINE NO.	DESCRIPTION	CORPORATE AS ADJUSTED ALLOCATED TO TGS Acct 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)
31	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0		
32	(386) Other Property on Customer Premises	0	0	0	0	0.0000%	0		
33	(387) Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0		
34	Total Distribution Plant	$0	$0	$0	$0		$0		$0
	GENERAL PLANT								
35	(389) Land & Land Rights	$0	$0	$0	$0	0.0000%	$0	46.4931%	$0
36	(390.1) Structures & Improvements	52,130	0	0	52,130	2.0100%	1,048	46.4931%	487
37	(390.2) Leasehold Improvements	1,270,520	87,174	0	1,357,693	13.0100%	176,636	46.4931%	82,124
38	(391.1) Office Furniture & Equipment	901,844	0	0	901,844	6.6667%	60,123	46.4931%	27,953
39	(391.19) Airplane Hanger Furniture	0	0	0	0	6.6667%	0	46.4931%	0
40	(391.2) Data Processing Equipment	0	0	0	0	0.0000%	0	46.4931%	0
41	(391.3) Office Machines	9,063	0	0	9,063	5.0000%	453	46.4931%	211
42	(391.4) Audio Visual Equipment	350,715	0	0	350,715	20.0000%	70,143	46.4931%	32,612
43	(391.5) Artwork	0	0	0	0	0.0000%	0	46.4931%	0
44	(391.6) Purchased Software	21,043,175	8,337,982	0	29,381,158	7.6923%	2,260,089	46.4931%	1,050,785
45	(391.6) Banner Software	1,663,919	0	0	1,663,919	7.6923%	127,994	46.4931%	59,508
46	(391.6) PowerPlant System	208,931	0	0	208,931	7.6923%	16,072	46.4931%	7,472
47	(391.6) Riskworks	0	0	0	0	7.6923%	0	46.4931%	0
48	(391.6) Maximo	770,306	0	0	770,306	7.6923%	59,254	46.4931%	27,549
49	(391.6) Dynamic Risk Assessment	0	0	0	0	7.6923%	0	46.4931%	0
50	(391.6) Concur Project	13,318	0	(13,318)	0	7.6923%	0	46.4931%	0
51	(391.6) Journey-Employee Count	17,399,028	0	0	17,399,028	7.6923%	1,338,387	46.4931%	622,257
52	(391.6) Journey-Employee-ODC Distrigas	516,769	0	0	516,769	7.6923%	39,751	46.4931%	18,482
53	(391.6) Ariba Software	0	0	0	0	7.6923%	0	46.4931%	-
54	(391.6) Accounts Payable Software	279,633	0	0	279,633	7.6923%	21,510	46.4931%	10,001
55	(391.8) Micro Computer Software	4,195,542	50,058	0	4,245,600	20.0000%	849,120	46.4931%	394,782
56	(391.81) Aircraft Computer Equipment	0	0	0	0	0.0000%	0	46.4931%	0
57	(391.9) Computer & Equipment	0	0	0	0	0.0000%	0	46.4931%	0
58	(392.6) Aircraft	0	0	0	0	6.2800%	0	46.4931%	0
59	(394) Tools	0	0	0	0	0.0000%	0	46.4931%	0
60	(394.1) Tools	0	0	0	0	0.0000%	0	46.4931%	0
61	(394.2) Shop Equipment	0	0	0	0	0.0000%	0	46.4931%	0

WKP G-15.c.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

DEPRECIATION AND AMORTIZATION EXPENSE - CORPORATE

LINE NO.	DESCRIPTION	CORPORATE AS ADJUSTED ALLOCATED TO TGS Acct 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)
62	(396) Major Work Equipment	0	0	0	0	0.0000%	0	46.4931%	0
63	(397) Communication Equipment	25,632	0	0	25,632	5.0000%	1,282	46.4931%	596
64	(397.2) Telephone Equipment	0	0	0	0	0.0000%	0	46.4931%	0
65	(398) Miscellaneous General Plant	0	0	0	0	0.0000%	0	46.4931%	0
66	Total General Plant	$48,700,525	$8,475,214	($13,318)	$57,162,421		$5,021,862		$2,334,819
67	Total Plant in Service	$48,700,525	$8,475,214	($13,318)	$57,162,421		$5,021,862		$2,334,819
68	Total Annualized Depreciation & Amortization Expense						$5,021,862	46.4931%	$2,334,819
69	Test Year Depreciation & Amortization Expense Accts 403 & 404						4,415,223	46.4931%	2,052,774
70	Adjustment to Test Year						$606,639	46.4931%	$282,045

WKP G-15.c.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

FULLY DEPRECIATED PLANT - CORPORATE

LINE NO.	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	Total Intangible Plant	$0	$0	$0	$0			
	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	0	0	0	0			
17	(368) Compressor Station Equip	0	0	0	0			
18	(369) Measure/Reg. Station Equipment	0	0	0	0			
19	(371) Other Equipment	0	0	0	0			
20	Total Gathering and Transmission Plant	$0	$0	$0	$0			
	DISTRIBUTION PLANT							
21	(374) Land & Land Rights	$0	$0	$0	$0			
22	(375.1) Structures & Improvements	0	0	0	0			
23	(376) Mains	0	0	0	0			
24	(377) Compressor Station Equipment	0	0	0	0			
25	(378) Meas. & Reg. Station - General	0	0	0	0			
26	(379) Meas. & Reg. Station - C.G.	0	0	0	0			
27	(380) Services	0	0	0	0			
28	(381) Meters	0	0	0	0			
29	(382) Meter Installations	0	0	0	0			
30	(383) House Regulators	0	0	0	0			
31	(385) Indust. Meas. & Reg. Stat. Equipment	0	0	0	0			
32	(386) Other Property on Customer Premises	0	0	0	0			
33	(387) Meas. & Reg. Stat. Equipment	0	0	0	0			
34	Total Distribution Plant	$0	$0	$0	$0			
	GENERAL PLANT							
35	(389) Land & Land Rights	$0	$0	$0	$0	25.01%	$0	$0
36	(390.1) Structures & Improvements	208,436	(1,416)	207,020	0	25.01%	0	51,776
37	(390.2) Leasehold Improvements	5,428,602	(2,133,609)	3,294,993	0	25.01%	0	824,078
38	(391.1) Office Furniture & Equipment	3,605,934	(858,753)	2,747,181	0	25.01%	0	687,070
39	(391.19) Airplane Hanger Furniture	0	0	0	0	25.01%	0	0
40	(391.2) Data Processing Equipment	0	0	0	0	25.01%	0	0
41	(391.3) Office Machines	36,237	(14,327)	21,910	0	25.01%	0	5,480
42	(391.4) Audio Visual Equipment	1,402,299	(1,090,138)	312,161	0	25.01%	0	78,072
43	(391.5) Artwork	0	0	0	0	25.01%	0	0
44	(391.6) Purchased Software	117,477,639	(27,585,936)	89,891,704	0	25.01%	0	22,481,915
45	(391.6) Banner Software	5,471,603	(1,292,482)	4,179,121	0	30.41%	0	1,270,874
46	(391.6) PowerPlant System	870,000	(361,608)	508,392	0	24.02%	0	122,090
47	(391.6) Riskworks	0	0	0	0	0.00%	0	0
48	(391.6) Maximo	3,117,561	(2,253,129)	864,432	0	24.71%	0	213,589
49	(391.6) Dynamic Risk Assessment	0	0	0	0	0.00%	0	0
50	(391.6) Concur Project	47,648	(47,648)	0	(47,648)	27.95%	(13,318)	0
51	(391.6) Journey-Employee Count	69,568,284	(26,272,810)	43,295,474	0	25.01%	0	10,828,198
52	(391.6) Journey-Employee-ODC Distrigas	1,848,836	(833,622)	1,015,214	0	27.95%	0	283,763
53	(391.6) Ariba Software	0	0	0	0	30.96%	0	0
54	(391.6) Accounts Payable Software	903,328	(141,534)	761,795	0	30.96%	0	235,820
55	(391.8) Micro Computer Software	16,975,609	(4,466,696)	12,508,913	0	25.01%	0	3,128,479
56	(391.81) Aircraft Computer Equipment	0	0	0	0	25.01%	0	0
57	(391.9) Computer & Equipment	0	0	0	0	25.01%	0	0
58	(392.6) Aircraft	0	0	0	0	25.01%	0	0
59	(394) Tools	0	0	0	0	25.01%	0	0
60	(394.1) Tools	0	0	0	0	25.01%	0	0
61	(394.2) Shop Equipment	0	0	0	0	25.01%	0	0
62	(396) Major Work Equipment	0	0	0	0	25.01%	0	0
63	(397) Communication Equipment	102,489	(10,663)	91,826	0	25.01%	0	22,966
64	(397.2) Telephone Equipment	0	0	0	0	25.01%	0	0
65	(398) Miscellaneous General Plant	0	0	0	0	25.01%	0	0

WKP G-15.c.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

FULLY DEPRECIATED PLANT - CORPORATE

LINE NO.	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)	
66	Total General Plant	$227,064,505	($67,364,369)	$159,700,136	($47,648)		($13,318)	$40,234,170
67	Total Orig Cost Plant in Service	$227,064,505	($67,364,369)	$159,700,136	($47,648)		($13,318)	$40,234,170

SCHEDULE G-16

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

AD VALOREM TAX EXPENSE

LINE NO.	DESCRIPTION	AMOUNT	AMOUNT	AMOUNT
		(a)	(b)	(c)
	DIRECT SERVICE AREA PLANT @ 6/30/2019			
1	Plant In Service - Gathering/Transmission/Distribution		$576,817,748	
2	Plant In Service - General		48,084,368	
3	CCNC - Gathering/Transmission/Distribution		58,506,577	
4	CCNC - General		1,416,077	
5	Accumulated Depreciation - Gathering/Transmission/Distribution		(155,429,600)	
6	Accumulated Depreciation - General		(19,487,854)	
7	Net Plant - Service Area Direct 6/30/2019		$509,907,316	$509,907,316
	CALCULATION OF EFFECTIVE RATE			
8	Ad Valorem Taxes Paid TYE June 2019 for Service Area Direct Plant at 1/1/2018		$3,857,908	
	DIRECT SERVICE AREA PLANT @ 1/1/2018:			
9	Plant In Service - Gathering/Transmission/Distribution	$534,736,158		
10	Plant In Service - General	44,428,856		
11	CCNC - Gathering/Transmission/Distribution	26,929,956		
12	CCNC - General	552,379		
13	Accumulated Depreciation - Gathering/Transmission/Distribution	(138,801,444)		
14	Accumulated Depreciation - General	(19,257,247)		
		$448,588,658	448,588,658	
15	Effective Tax Rate		0.008600	0.008600
16	Annualized Ad Valorem Tax Expense			$4,385,203
17	Test Year Ad Valorem Tax Expense - Acct 4081190			4,083,352
18	Adjustment to Test Year Expense			$301,851

Source: WKP G-16 Ad Valorem Tax Liablility CGSA.xlsx

WKP G-16.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PLANT IN SERVICE - DIRECT
AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/17	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)
	INTANGIBLE PLANT (NOT USED FOR AD VALOREM)			
1	(301) Organization	$56,257	$0	$56,257
2	(302) Franchises & Consents	393,474	0	393,474
3	(303) Misc. Intangible	739,593	0	739,593
4	Total Intangible Plant - Direct	$1,189,323	$0	$1,189,323
	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	3,505,814	0	3,505,814
17	(368) Compressor Station Equip	0	0	0
18	(369) Measure/Reg. Station Equipment	211,577	0	211,577
19	(371) Other Equipment	0	0	0
20	Total Gathering and Transmission Plant - Direct	$3,717,391	$0	$3,717,391
	DISTRIBUTION PLANT			
21	(374) Land & Land Rights	$115,176	$0	$115,176
22	(375) Structures & Improvements	48,935	0	48,935
23	(376) Mains	257,814,291	0	257,814,291
24	(376.9) Cathodic Protection Anodes	26,174,737	0	26,174,737
25	(377) Compressor Station Equipment	0	0	0
26	(378) Meas. & Reg. Station - General	8,850,734	0	8,850,734
27	(379) Meas. & Reg. Station - C.G.	1,894,244	0	1,894,244
28	(380) Services	156,230,841	0	156,230,841
29	(381) Meters	58,768,635	0	58,768,635
30	(382) Meter Installations	0	0	0
31	(383) House Regulators	8,482,219	0	8,482,219
32	(385) Indust. Meas. & Reg. Stat. Equipment	11,575,705	0	11,575,705
33	(386) Other Property on Customer Premises	1,063,249	0	1,063,249
34	(387) Meas. & Reg. Stat. Equipment	0	0	0
35	Total Distribution Plant - Direct	$531,018,767	$0	$531,018,767
	GENERAL PLANT			
36	(389) Land & Land Rights	$48,883	$0	$48,883
37	(390) Structures & Improvements	5,283,423	0	5,283,423
38	(391) Office Furniture & Equipment	5,166,668	0	5,166,668
39	(392) Transportation Equipment	9,597,320	0	9,597,320
40	(393) Stores Equipment	6,354	0	6,354
41	(394) Tools, Shop & Garage	5,215,462	0	5,215,462
42	(395) CNG Equipment	0	0	0
43	(396) Major Work Equipment	1,342,855	0	1,342,855
44	(397) Communication Equipment	17,637,531	0	17,637,531
45	(398) Miscellaneous General Plant	130,360	0	130,360
46	Total General Plant - Direct	$44,428,856	$0	$44,428,856
47	Total Orig Cost Plant in Service - Direct	$580,354,338	$0	$580,354,338

Source: WKP G-16.a CGSA_091_PP Rpt_1010_Plant In Service Dec 31 2017.xlsx

WKP G-16.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPLETED CONSTRUCTION NOT CLASSIFIED (CCNC) - DIRECT
AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/17	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	1,923,181	0	1,923,181
17	(368) Compressor Station Equip	0	0	0
18	(369) Measure/Reg. Station Equipment	322,213	0	322,213
19	(371) Other Equipment	0	0	0
20	Total Gathering and Transmission CCNC - Direct	$2,245,394	$0	$2,245,394
	DISTRIBUTION PLANT			
21	(374) Land & Land Rights	$3,827	$0	$3,827
22	(375) Structures & Improvements	0	0	0
23	(376) Mains	18,499,701	0	18,499,701
24	(376.9) Cathodic Proteciton Anodes	9,802	0	9,802
25	(377) Compressor Station Equipment	0	0	0
26	(378) Meas. & Reg. Station - General	3,044,451	0	3,044,451
27	(379) Meas. & Reg. Station - C.G.	7	0	7
28	(380) Services	2,215,506	0	2,215,506
29	(381) Meters	176,967	0	176,967
30	(382) Meter Installations	8,750	0	8,750
31	(383) House Regulators	24,715	0	24,715
32	(385) Indust. Meas. & Reg. Stat. Equipment	700,837	0	700,837
33	(386) Other Property on Customer Premises	0	0	0
34	(387) Meas. & Reg. Stat. Equipment	0	0	0
35	Total Distribution CCNC - Direct	$24,684,562	$0	$24,684,562
	GENERAL PLANT			
36	(389) Land & Land Rights	$0	$0	$0
37	(390) Structures & Improvements	142,961	0	142,961
38	(391) Office Furniture & Equipment	236	0	236
39	(392) Transportation Equipment	239,161	0	239,161
40	(393) Stores Equipment	0	0	0
41	(394) Tools, Shop & Garage	108,463	0	108,463
42	(395) CNG Equipment	0	0	0
43	(396) Major Work Equipment	0	0	0
44	(397) Communication Equipment	61,559	0	61,559
45	(398) Miscellaneous General Plant	0	0	0
46	Total General CCNC - Direct	$552,379	$0	$552,379
47	Total Orig Cost CCNC - Direct	$27,482,336	$0	$27,482,336

Source: WKP G-16.b CGSA_091_PP Rpt_1060_CCNC Dec 31 2017.xlsx

WKP G-16.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

ACCUMULATED RESERVES FOR DEPRECIATION AND AMORTIZATION- DIRECT
AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/17 1080100	YTD BALANCE 12/31/17 1110000	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)	(d)
	INTANGIBLE PLANT (NOT USED FOR AD VALOREM)				
1	(301) Organization	($40,240)	$0	$0	($40,240)
2	(302) Franchises & Consents	(394,841)	0	0	(394,841)
3	(303) Misc. Intangible	$0	(721,885)	0	(721,885)
4	Total Intangible Plant Reserves - Direct	($435,081)	($721,885)	$0	($1,156,966)
	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	(1,783,991)	0	0	(1,783,991)
17	(368) Compressor Station Equip	$0	0	0	0
18	(369) Measure/Reg. Station Equipment	(19,245)	0	0	(19,245)
19	(371) Other Equipment	$0	0	0	0
20	Total Gathering and Transmission Plant Reserves - Direct	($1,803,236)	$0	$0	($1,803,236)
	DISTRIBUTION PLANT				
21	(374) Land & Land Rights	($9,695)	$0	$0	($9,695)
22	(375) Structures & Improvements	6,374	0	0	6,374
23	(376) Mains	(61,274,209)	0	0	(61,274,209)
24	(376.9) Cathodic Protection Anodes	(7,843,795)	0	0	(7,843,795)
25	(377) Compressor Station Equipment	0	0	0	0
26	(378) Meas. & Reg. Station - General	(2,485,893)	0	0	(2,485,893)
27	(379) Meas. & Reg. Station - C.G.	(625,234)	0	0	(625,234)
28	(380) Services	(34,158,511)	0	0	(34,158,511)
29	(381) Meters	(21,574,983)	0	0	(21,574,983)
30	(382) Meter Installations	(9,938)	0	0	(9,938)
31	(383) House Regulators	(3,853,647)	0	0	(3,853,647)
32	(385) Indust. Meas. & Reg. Stat. Equipment	(4,099,283)	0	0	(4,099,283)
33	(386) Other Property on Customer Premises	(1,069,395)	0	0	(1,069,395)
34	(387) Meas. & Reg. Stat. Equipment	$0	0	0	0
35	Total Distribution Plant Reserves - Direct	($136,998,208)	$0	$0	(136,998,208)
	GENERAL PLANT				
36	(389) Land & Land Rights	$3,573	$0	$0	$3,573
37	(390) Structures & Improvements	(2,655,984)	(704,994)	0	(3,360,978)
38	(391) Office Furniture & Equipment	(489,230)	0	0	(489,230)
39	(391.9) Computer & Equipment	($3,286,103)	0	0	(3,286,103)
40	(392) Transportation Equipment	(3,534,323)	0	0	(3,534,323)
41	(393) Stores Equipment	(7,021)	0	0	(7,021)
42	(394) Tools, Shop & Garage	(2,037,046)	0	0	(2,037,046)
43	(395) CNG Equipment	37,480	0	0	37,480
44	(396) Major Work Equipment	(705,505)	0	0	(705,505)
45	(397) Communication Equipment	(5,813,143)	0	0	(5,813,143)
46	(398) Miscellaneous General Plant	(64,952)	0	0	(64,952)
47	Total General Plant Reserves - Direct	($18,552,253)	($704,994)	$0	($19,257,247)
48	Total Accumulated Reserves - Direct	($157,788,778)	($1,426,880)	$0	($159,215,658)

Source: WKP G-16.c CGSA_091_PP Rpt_1080100 & 1110 Dec 31 2017.xlsx
Source: WKP G-16.c CGSA_091_PP Rpt_1080100_Accum Depr Dec 31 2017.xlsx
Source: WKP G-16.c.2 CGSA_091_PP Rpt_1110_Accum Amort Dec 31 2017.xlsx

SCHEDULE G-17

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

TEXAS FRANCHISE ("GROSS MARGIN") TAX EXPENSE

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
			(a)
1	As Adjusted Base (Non-Gas) Revenue	WKP G.a.1	$109,004,207
	Less:		
2	Taxes Other Than Federal Income Tax - Revenue Related	WKP G.a.1	13,277
3	Bad Debt Expense, not included in Purchased Gas Costs	WKP G.a.1	585,680
	Gross Profit		$108,405,250
4	Tax Rate		0.0075
5	Gross Margin Tax		$813,039
6	Test Year Expense - Acct 4091100		0
7	Adjustment to Test Year		$813,039

SCHEDULE G-18

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

STORES LOAD CLEARING

LINE NO.	DESCRIPTION				AMOUNT
		(a)	(b)	(c)	(d)
1	Test Year Charges into Stores Account 1630 for direct and allocated charges:		$1,504,246		
2	Test Year Amounts Cleared Out of Account 1630 to Service Area		1,325,837		
3	Test Year Amount Under/(Over) Cleared		$178,408		$178,408
	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)	$274,232	$270,510	$3,722	
5	Benefits & Payroll Taxes	122,964	116,036	6,928	
6	Other	1,121,316	1,117,699	3,617	
7	Total Other Adjustments	$1,518,512	$1,504,246	$14,266	14,266
8	Total Adjusted Amount Under/(Over) Cleared				$192,674
	Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:				
9	**Adjustment to Test Year Expense Accounts (See account breakdown below)**				$15,588
10	Adjustment to Test Year Non-Expense Accounts				177,086
11	Total Adjustment to Test Year Clearing Acct 1630				$192,674

	Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:				Amount Under/
12		Acct.	Amount	Percentage	(Over) Cleared
13		8700	$37	0.000028	$5
14		8740	30,546	0.023039	4,439
15		8750	4	0.000003	1
16		8770	37	0.000028	5
17		8780	27,771	0.020946	4,036
18		8800	2,734	0.002062	397
19		8870	31,394	0.023679	4,562
20		8890	173	0.000131	25
21		8920	14,042	0.010591	2,041
22		9020	525	0.000396	76
23		9210	2	0.000001	0
24	Total Adjustment to Test Year Expense Accounts		$107,266	0.080904	$15,588
25	Total Adjustment to Test Year Non-Expense Accounts		1,218,572	0.919096	177,086
	Adjustment to Test Year Clearing		$1,325,837	1.000000	$192,674

Source: SCH G-18 CGSA Stores Clearing Adjustment (CONFIDENTIAL).xlsx

SCHEDULE G-19

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

TRANSPORTATION AND WORK EQUIPMENT CLEARING

LINE NO.	DESCRIPTION				AMOUNT
		(a)	(b)	(c)	(d)
1	Test Year Charges into TWE Clearing Accounts 1840100-1840289		$2,610,433		
2	Test Year Amounts Cleared Out of TWE Accounts 1840100-1840289		2,391,848		
3	Test Year Amount Under/(Over) Cleared		$218,585		$218,585
	Plus/Minus Adjustments To Test Year Amounts Charged into TWE Acct 1840100-1840289:				
		Adjusted Test Year	Recorded Test Year	Adjustment	
4	Depreciation	$1,235,514	$940,620	$294,894	
5	Lease Costs	0	0	0	
6	Payroll	92,973	85,889	7,084	
7	Benefits & Payroll Taxes	238,429	243,843	(5,414)	
8	Other (gasoline, maintenance, etc)	2,280,702	2,280,702	0	
9	Total	$3,847,618	$3,551,054	$296,564	296,564
10	Total Adjusted Amount Under/(Over) Cleared				$515,150
	Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:				
11	Adjustment to Test Year Expense Accounts (See account breakdown below)				$328,562
12	Adjustment to Test Year Non-Expense Accounts				186,588
13	Total Adjustment to Test Year TWE Clearing Acct 1840				$515,150

	Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:				Amount Under/
14		Acct.	Amount	Percentage	(Over) Cleared
15		8560	$31,685	0.013247	$6,824
16		8630	23	0.000010	5
17		8700	14,171	0.005925	3,052
18		8740	143,181	0.059862	30,838
19		8750	21,692	0.009069	4,672
20		8760	1,918	0.000802	413
21		8770	62	0.000026	13
22		8780	531,260	0.222113	114,421
23		8790	16,498	0.006898	3,553
24		8800	80,992	0.033862	17,444
25		8870	338,293	0.141436	72,861
26		8890	47,098	0.019691	10,144
27		8900	80,387	0.033609	17,314
28		8910	2,104	0.000880	453
29		8920	97,825	0.040899	21,069
30		8930	218	0.000091	47
31		9020	85,600	0.035788	18,436
32		9030	28,867	0.012069	6,217
33		9050	1,576	0.000659	340
34		9210	2,067	0.000864	445.137
35	Total Adjustment to Test Year Expense Accounts		$1,525,518	0.637799	$328,562
36	Total Adjustment to Test Year Non-Expense Accounts		866,330	0.362201	186,588
37	Adjustment to Test Year Clearing		$2,391,848	1.000000	$515,150

Source: SCH G-19 CGSA TWE Clearing Adjustment (CONFIDENTIAL).xlsx

SCHEDULE G-20

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

REGULATORY EXPENSE AMORTIZATION

LINE NO.	DESCRIPTION	AMOUNT
		(a)
1	Regulatory Asset - Regulatory Expense at June 2019	$155,665
2	Less 10 mos. Amortization (line 20, July 2019 - April 2020) Note 1	(38,916)
3	Regulatory Asset - Regulatory Expense at April 2020	$116,749
4	Amortization Period (in years)	6
5	Annual Regulatory Amortization Expense	$19,458
6	Test Year Regulatory Amortization Expense - Acct 407.3	46,699
7	Adjustment to Test Year Expense	($27,241)

Note 1: Amortization of Regulatory Asset between end of Test Year and beginning of effective rates.

	MONTH	2019	2020	GRAND TOTAL
8	January		(3,892)	(3,892)
9	February		(3,892)	(3,892)
10	March		(3,892)	(3,892)
11	April		(3,892)	(3,892)
12	May			-
13	June			-
14	July	(3,892)		(3,892)
15	August	(3,892)		(3,892)
16	September	(3,892)		(3,892)
17	October	(3,892)		(3,892)
18	November	(3,892)		(3,892)
19	December	(3,892)		(3,892)
20				**($38,916)**

Source: SCH G-20 CGSA Regulatory Expense (CONFIDENTIAL).xlsx

SCHEDULE G-21

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

DISTRIGAS ALLOCATION PERCENTAGE

							ADJUSTMENT FOR Q3 2019 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	2018	7	$285,068	24.51%	$69,870			
2		2018	8	300,790	24.51%	73,724			
3		2018	9	314,271	24.51%	77,028			
4		2018	10	260,005	24.65%	64,091			
5		2018	11	255,580	24.65%	63,001			
6		2018	12	412,876	24.65%	101,774			
7		2019	1	389,245	24.72%	96,221			
8		2019	2	809,792	24.72%	200,181			
9		2019	3	524,244	24.72%	129,593			
10		2019	4	300,599	24.71%	74,278			
11		2019	5	321,009	24.71%	79,321			
12		2019	6	453,359	24.71%	112,025			
13	4081 Total			$4,626,839		$1,141,107			
14	9260	2018	7	$688,989	24.51%	$168,871			
15		2018	8	688,989	24.51%	168,871			
16		2018	9	688,989	24.51%	168,871			
17		2018	10	688,989	24.65%	169,836			
18		2018	11	688,989	24.65%	169,836			
19		2018	12	688,989	24.65%	169,836			
20		2019	1	570,981	24.72%	141,147			
21		2019	2	570,981	24.72%	141,147			
22		2019	3	570,981	24.72%	141,147			
23		2019	4	570,981	24.71%	141,089			
24		2019	5	570,981	24.71%	141,089			
25		2019	6	570,981	24.71%	141,089			
26	9260 Total			$7,559,820		$1,862,829			
27	9302	2018	7	$7,019,065	24.51%	$1,720,373			
28		2018	8	6,383,336	24.51%	1,564,556			
29		2018	9	7,917,692	24.51%	1,940,626			
30		2018	10	5,908,834	24.65%	1,456,528			
31		2018	11	6,681,173	24.65%	1,646,909			
32		2018	12	10,709,919	24.65%	2,639,995			
33		2019	1	6,992,317	24.72%	1,728,501			
34		2019	2	7,022,842	24.72%	1,736,047			
35		2019	3	12,206,577	24.72%	3,017,466			
36		2019	4	7,046,866	24.71%	1,741,280			
37		2019	5	6,593,142	24.71%	1,629,165			
38		2019	6	10,780,870	24.71%	2,663,953			
39	9302 Total			$95,262,634		$23,485,399	25.0100%	$23,825,185	$339,786
40	Total			$107,449,293		$26,489,335		$23,825,185	$339,786
41								O&M Expense Factor	88.69%
42								Adjustment to TGS O&M	301,360
43								Allocation to Service Area	46.4931%
44								Adjustment to Service Area after O&M	$140,112

WKP G-21.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
	3rd Quarter 2018 - based on 12 months Ended Jun 2018							
1	Oklahoma Natural Gas Company	$2,408,783,564	42.61%	$145,398,721	48.13%	$50,208,794	36.59%	42.44%
2	Kansas Gas Service Company	1,896,122,266	33.54%	84,138,981	27.85%	50,962,405	37.14%	32.84%
3	Texas Gas Service Company	1,347,932,056	23.85%	70,692,735	23.40%	36,055,077	26.27%	**24.51%**
4	Utility Insurance Company	0	0.00%	1,867,256	0.62%	0	0.00%	0.21%
5	Total	$5,652,837,887	100.00%	$302,097,692	100.00%	$137,226,276	100.00%	100.00%
	4th Quarter 2018 - based on 12 months Ended Sept 2018							
6	Oklahoma Natural Gas Company	$2,445,159,066	42.59%	$144,175,253	48.92%	$50,071,927	36.56%	42.69%
7	Kansas Gas Service Company	1,921,866,225	33.48%	78,831,679	26.75%	50,854,958	37.13%	32.45%
8	Texas Gas Service Company	1,373,889,963	23.93%	69,883,546	23.71%	36,036,771	26.31%	**24.65%**
9	Utility Insurance Company	0	0.00%	1,811,503	0.61%	0	0.00%	0.20%
10	Total	$5,740,915,253	100.00%	$294,701,981	100.00%	$136,963,656	100.00%	100.00%
	1st Quarter 2019 - based on 12 months Ended Dec 2018							
11	Oklahoma Natural Gas Company	$2,490,046,126	42.63%	$155,006,365	52.49%	$50,124,043	36.37%	43.83%
12	Kansas Gas Service Company	1,947,858,163	33.35%	70,821,231	23.98%	51,027,462	37.02%	31.45%
13	Texas Gas Service Company	1,402,597,349	24.02%	69,475,672	23.53%	36,671,087	26.61%	**24.72%**
14	Utility Insurance Company	0	0.00%	0	0.00%	0	0.00%	0.00%
15	Total	$5,840,501,638	100.00%	$295,303,268	100.00%	$137,822,591	100.00%	100.00%
	2nd Quarter 2019 - based on 12 months Ended Mar 2019							
16	Oklahoma Natural Gas Company	$2,524,763,738	42.71%	$148,483,746	50.36%	$50,098,662	36.29%	43.12%
17	Kansas Gas Service Company	1,961,719,086	33.18%	78,335,430	26.57%	50,779,890	36.78%	32.18%
18	Texas Gas Service Company	1,425,619,901	24.11%	68,010,875	23.07%	37,191,014	26.94%	**24.71%**
19	Utility Insurance Company	0	0.00%	0	0.00%	0	0.00%	0.00%
20	Total	$5,912,102,726	100.00%	$294,830,051	100.00%	$138,069,567	100.01%	100.01%
	3rd Quarter 2019 - based on 12 months Ended Jun 2019							
21	Oklahoma Natural Gas Company	$2,563,955,976	42.73%	$144,440,955	48.59%	$50,480,130	36.26%	42.53%
22	Kansas Gas Service Company	1,982,241,525	33.04%	82,084,916	27.61%	51,023,106	36.65%	32.43%
23	Texas Gas Service Company	1,451,696,573	24.19%	70,574,450	23.74%	37,721,351	27.09%	**25.01%**
24	ONE Gas Pipeline	2,525,233	0.04%	190,000	0.06%	0	0.00%	0.03%
25	Utility Insurance Company	0	0.00%	0	0.00%	0	0.00%	0.00%
26	Total	$6,000,419,307	100.00%	$297,290,322	100.00%	$139,224,587	100.00%	100.00%

SCHEDULE G-22

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	2018	7	$35,844	21.00%	$7,527
2	Invoice Count	2018	8	43,688	21.00%	9,175
3	Invoice Count	2018	9	35,795	21.00%	7,517
4	Invoice Count	2018	10	31,789	21.00%	6,676
5	Invoice Count	2018	11	26,579	21.00%	5,582
6	Invoice Count	2018	12	30,032	21.00%	6,307
7	Invoice Count	2019	1	28,050	22.04%	6,182
8	Invoice Count	2019	2	29,071	22.04%	6,407
9	Invoice Count	2019	3	35,467	22.04%	7,817
10	Invoice Count	2019	4	28,773	22.04%	6,342
11	Invoice Count	2019	5	28,487	22.04%	6,279
12	Invoice Count	2019	6	32,187	22.04%	7,094
13	**Invoice Count Total**			**$385,762**		**$82,903**
14	Employee Headcount	2018	7	$811,184	23.82%	$193,224
15	Employee Headcount	2018	8	1,020,491	23.82%	243,081
16	Employee Headcount	2018	9	856,879	23.82%	204,108
17	Employee Headcount	2018	10	1,000,091	23.82%	238,222
18	Employee Headcount	2018	11	946,477	23.82%	225,451
19	Employee Headcount	2018	12	1,128,416	23.82%	268,789
20	Employee Headcount	2019	1	930,622	23.82%	221,674
21	Employee Headcount	2019	2	962,294	23.96%	230,566
22	Employee Headcount	2019	3	995,135	23.96%	238,434
23	Employee Headcount	2019	4	964,382	23.96%	231,066
24	Employee Headcount	2019	5	943,859	23.96%	226,149
25	Employee Headcount	2019	6	893,869	23.96%	214,171
26	**Employee Headcount Total**			**$11,453,700**		**$2,734,935**
27	Gross PP&E	2018	7	$97	23.57%	$23
28	Gross PP&E	2018	8	3,196	23.57%	753
29	Gross PP&E	2018	9	584	23.57%	138
30	Gross PP&E	2018	10	296	23.57%	70
31	Gross PP&E	2018	11	3,521	23.57%	830
32	Gross PP&E	2018	12	1,411	23.57%	333
33	Gross PP&E	2019	1	623	24.02%	150
34	Gross PP&E	2019	2	3,265	24.02%	784
35	Gross PP&E	2019	3	2,239	24.02%	538
36	Gross PP&E	2019	4	78	24.02%	19
37	Gross PP&E	2019	5	596	24.02%	143
38	Gross PP&E	2019	6	7,641	24.02%	1,835
39	**Gross PP&E Total**			**$23,549**		**$5,615**
40	Budgeted Admin Cost-SERP	2018	7	$2,030	0.00%	$0
41	Budgeted Admin Cost-SERP	2018	2	4,124	0.00%	0
42	Budgeted Admin Cost-SERP	2018	3	8,324	0.00%	0
43	Budgeted Admin Cost-SERP	2018	4	1,800	0.00%	0
44	Budgeted Admin Cost-SERP	2018	5	2,062	0.00%	0
45	Budgeted Admin Cost-SERP	2018	6	6,800	0.00%	0
46	Budgeted Admin Cost-SERP	2018	7	5,451	0.42%	23
47	Budgeted Admin Cost-SERP	2019	8	22,995	0.42%	97
48	Budgeted Admin Cost-SERP	2019	9	(8,601)	0.42%	(36)

SCHEDULE G-22

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CAUSAL ALLOCATION PERCENTAGE

LINE NO.	CAUSAL METHOD	YEAR	MONTH	CORPORATE ALLOCABLE $	CAUSAL ALLOCATION %	$ ALLOCATED TO TGS
		(a)	(b)	(c)	(d)	(e)=(c) x (d)
49	Budgeted Admin Cost-SERP	2019	10	1,944	0.42%	8
50	Budgeted Admin Cost-SERP	2019	11	7,280	0.42%	31
51	Budgeted Admin Cost-SERP	2019	12	7,324	0.42%	31
52	**Budgeted Admin Cost-SERP Total**			**$61,533**		**$153**
53	Budgeted Admin Cost-Pension	2018	7	$488	19.47%	$95
54	Budgeted Admin Cost-Pension	2018	8	1,112	19.47%	216
55	Budgeted Admin Cost-Pension	2018	9	914	19.47%	178
56	Budgeted Admin Cost-Pension	2018	10	457	19.47%	89
57	Budgeted Admin Cost-Pension	2018	11	(69,543)	19.47%	(13,540)
58	Budgeted Admin Cost-Pension	2018	12	852	19.47%	166
59	Budgeted Admin Cost-Pension	2019	1	9,006	17.75%	1,599
60	Budgeted Admin Cost-Pension	2019	2	(19,001)	17.75%	(3,373)
61	Budgeted Admin Cost-Pension	2019	3	661	17.75%	117
62	Budgeted Admin Cost-Pension	2019	4	661	17.75%	117
63	Budgeted Admin Cost-Pension	2019	5	1,984	17.75%	352
64	Budgeted Admin Cost-Pension	2019	6	661	17.75%	117
65	**Budgeted Admin Cost-Pension Total**			**($71,747)**		**($13,865)**
66	Customer Count	2018	7	$447,156	30.31%	$135,533
67	Customer Count	2018	8	518,733	30.31%	157,228
68	Customer Count	2018	9	488,989	30.31%	148,213
69	Customer Count	2018	10	551,481	30.31%	167,154
70	Customer Count	2018	11	626,437	30.31%	189,873
71	Customer Count	2018	12	549,314	30.31%	166,497
72	Customer Count	2019	1	460,694	30.41%	140,097
73	Customer Count	2019	2	441,285	30.41%	134,195
74	Customer Count	2019	3	477,857	30.41%	145,316
75	Customer Count	2019	4	457,266	30.41%	139,055
76	Customer Count	2019	5	516,103	30.41%	156,947
77	Customer Count	2019	6	490,149	30.41%	149,054
78	**Customer Count Total**			**$6,025,464**		**$1,829,162**
79	ALLOCATE BY MILES OF PIPE	2018	7	$258,875	24.77%	$64,123
80	ALLOCATE BY MILES OF PIPE	2018	8	212,087	24.77%	52,534
81	ALLOCATE BY MILES OF PIPE	2018	9	358,230	24.77%	88,734
82	ALLOCATE BY MILES OF PIPE	2018	10	221,197	24.77%	54,790
83	ALLOCATE BY MILES OF PIPE	2018	11	270,891	24.77%	67,100
84	ALLOCATE BY MILES OF PIPE	2018	12	463,768	24.77%	114,875
85	ALLOCATE BY MILES OF PIPE	2019	1	209,891	24.71%	51,864
86	ALLOCATE BY MILES OF PIPE	2019	2	181,129	24.71%	44,757
87	ALLOCATE BY MILES OF PIPE	2019	3	213,037	24.71%	52,641
88	ALLOCATE BY MILES OF PIPE	2019	4	241,125	24.71%	59,582
89	ALLOCATE BY MILES OF PIPE	2019	5	389,542	24.71%	96,256
90	ALLOCATE BY MILES OF PIPE	2019	6	211,847	24.71%	52,347
91	**Miles of Pipe Total**			**$3,231,618**		**$799,604**
92	ALLOCATE BY PROFIT SHARE	2018	7	($4,923)	24.00%	($1,182)
93	ALLOCATE BY PROFIT SHARE	2018	8	(1,494)	24.00%	(358)
94	ALLOCATE BY PROFIT SHARE	2018	9	56,000	24.00%	13,440
95	ALLOCATE BY PROFIT SHARE	2018	10	(3,962)	24.00%	(951)
96	ALLOCATE BY PROFIT SHARE	2018	11	0	24.00%	0
97	ALLOCATE BY PROFIT SHARE	2018	12	54,617	24.00%	13,108
98	ALLOCATE BY PROFIT SHARE	2019	1	8,374	23.96%	2,006
99	ALLOCATE BY PROFIT SHARE	2019	2	1,370	23.96%	328
100	ALLOCATE BY PROFIT SHARE	2019	3	56,300	23.96%	13,489
101	ALLOCATE BY PROFIT SHARE	2019	4	(2,670)	23.96%	(640)

SCHEDULE G-22

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CAUSAL ALLOCATION PERCENTAGE

LINE NO.	CAUSAL METHOD	YEAR	MONTH	CORPORATE ALLOCABLE $	CAUSAL ALLOCATION %	$ ALLOCATED TO TGS
		(a)	(b)	(c)	(d)	(e)=(c) x (d)
102	ALLOCATE BY PROFIT SHARE	2019	5	230	23.96%	55
103	ALLOCATE BY PROFIT SHARE	2019	6	74,800	23.96%	17,922
104	**ALLOCATE BY PROFIT SHARE Total**			**$238,642**		**$57,219**
105	ALLOCATE BY THRIFT	2018	7	($13,471)	20.00%	($2,694)
106	ALLOCATE BY THRIFT	2018	8	(776)	20.00%	(155)
107	ALLOCATE BY THRIFT	2018	9	75,000	20.00%	15,000
108	ALLOCATE BY THRIFT	2018	10	(15,625)	20.00%	(3,125)
109	ALLOCATE BY THRIFT	2018	11	0	20.00%	0
110	ALLOCATE BY THRIFT	2018	12	75,852	20.00%	15,170
111	ALLOCATE BY THRIFT	2019	1	(31,833)	23.96%	(7,627)
112	ALLOCATE BY THRIFT	2019	2	(60)	23.96%	(14)
113	ALLOCATE BY THRIFT	2019	3	75,000	23.96%	17,970
114	ALLOCATE BY THRIFT	2019	4	(16,123)	23.96%	(3,863)
115	ALLOCATE BY THRIFT	2019	5	165	23.96%	40
116	ALLOCATE BY THRIFT	2019	6	93,500	23.96%	22,403
117	**ALLOCATE BY THRIFT Total**			**$241,629**		**$53,104**
118	**Total**			**$21,590,151**		**$5,548,828**

WKP G-22.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CAUSAL ALLOCATION FACTORS

	2018			2019		
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 2017	Invoices		Based on number of invoices processed by company in 2018	Invoices	
1	Oklahoma Natural Gas Company	48,948	25.00%	Oklahoma Natural Gas Company	43,278	24.47%
2	Kansas Gas Service Company	34,142	17.00%	Kansas Gas Service Company	31,167	17.62%
3	Texas Gas Service Company	41,488	**21.00%**	Texas Gas Service Company	38,983	**22.04%**
4	ONE Gas Inc.	72,650	37.00%	ONE Gas Inc.	63,042	35.64%
5	Utility Insurance Company	15	0.00%	Utility Insurance Company	40	0.02%
6	ONE Gas Foundation	371	0.00%	ONE Gas Foundation	354	0.20%
7	Total	197,614	100%	Total	176,864	100.00%
	Based on employee headcount in 2017	Employees		Based on employee headcount in 2018	Employees	
8	Oklahoma Natural Gas Company	1,144	31.80%	Oklahoma Natural Gas Company	1,116	31.50%
9	Kansas Gas Service Company	1,036	28.79%	Kansas Gas Service Company	1,013	28.59%
10	Texas Gas Service Company	857	**23.82%**	Texas Gas Service Company	849	**23.96%**
11	ONE Gas Inc.	561	15.59%	ONE Gas Inc.	565	15.95%
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	3,598	100%	Total	3,543	100%
	Based on Gross PP&E year end 2017	Gross PP&E		Based on Gross PP&E year end 2018	Gross PP&E	
15	Oklahoma Natural Gas Company	$2,345,655,874	42.65%	Oklahoma Natural Gas Company	$2,490,046,126	42.63%
16	Kansas Gas Service Company	1,858,077,236	33.78%	Kansas Gas Service Company	1,947,858,163	33.35%
17	Texas Gas Service Company	1,296,572,956	**23.57%**	Texas Gas Service Company	1,402,597,349	**24.02%**
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	$5,500,306,066	100%	Total	$5,840,501,638	100%
	Based on Miles of Pipe at year end 2017	Miles		Based on Miles of Pipe at year end 2018	Miles	
22	Oklahoma Natural Gas Company	19,200	44.86%	Oklahoma Natural Gas Company	19,300	44.99%
23	Kansas Gas Service Company	13,000	30.37%	Kansas Gas Service Company	13,000	30.30%
24	Texas Gas Service Company	10,600	**24.77%**	Texas Gas Service Company	10,600	**24.71%**
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	42,800	100%	Total	42,900	100%
	Based on Customer Count at year end 2017	Customers		Based on Customer Count at year end 2018	Customers	
29	Oklahoma Natural Gas Company	871,482	40.23%	Oklahoma Natural Gas Company	876,635	40.24%
30	Kansas Gas Service Company	638,119	29.46%	Kansas Gas Service Company	639,410	29.35%
31	Texas Gas Service Company	656,480	**30.31%**	Texas Gas Service Company	662,496	**30.41%**
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	2,166,081	100%	Total	2,178,541	100%
	SERP Adminstrative costs are allocated using Distrigas in 2018. These costs were incurred by Corporate only.			Based on each company's percent of budgeted admin cost for SERP for 2019	Percent of Total Cost	
36				Oklahoma Natural Gas Company	$287,668	11.75%

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CAUSAL ALLOCATION FACTORS

LINE NO.	DESCRIPTION (2018)	CAUSAL METRIC (a)	CAUSAL ALLOCATION FACTOR (b)	DESCRIPTION (2019)	CAUSAL METRIC (c)	CAUSAL ALLOCATION FACTOR (d)
37				Kansas Gas Service Company	585,136	23.89%
38				Texas Gas Service Company	10,291	**0.42%**
39				ONE Gas Inc.	1,565,698	63.94%
40				Utility Insurance Company	0	0.00%
41				ONE Gas Foundation	0	0.00%
42				Total	$2,448,793	100%
	Based on each company's percent of deferal Profit Sharing cost for 2018					
		Percent of Total Cost		Profit Share based on company's employee head count for 2019	Profit Share	
43	Oklahoma Natural Gas Company	$2,088,542	27.00%	Oklahoma Natural Gas Company	1,116	31.50%
44	Kansas Gas Service Company	1,856,482	24.00%	Kansas Gas Service Company	1,013	28.59%
45	Texas Gas Service Company	1,856,482	**24.00%**	Texas Gas Service Company	849	**23.96%**
46	ONE Gas Inc.	1,933,838	25.00%	ONE Gas Inc.	565	15.95%
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	$7,735,344	100%	Total	$3,543	100%
	Based on each company's percent of total cost of Pension for 2018			Based on each company's percent of total cost of Pension for 2019		
		Percent of Total Cost			Percent of Total Cost	
50	Oklahoma Natural Gas Company	$3,597,196	29.03%	Oklahoma Natural Gas Company	($79,678)	-0.37%
51	Kansas Gas Service Company	3,963,287	31.98%	Kansas Gas Service Company	12,675,880	59.12%
52	Texas Gas Service Company	2,414,290	**19.48%**	Texas Gas Service Company	3,805,659	**17.75%**
53	ONE Gas Inc.	2,417,427	19.51%	ONE Gas Inc.	5,037,391	23.50%
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	$12,392,200	100%	Utility Insurance Company	0	0.00%
				Total	$21,439,252	100%
	Based on each company's percent of Thrift cost for 2018					
		Percent of Total Cost		Thrift based on company's employee head count for 2019	Thrift	
57	Oklahoma Natural Gas Company	$3,522,275	28.50%	Oklahoma Natural Gas Company	1,116	31.50%
58	Kansas Gas Service Company	3,769,452	30.50%	Kansas Gas Service Company	1,013	28.59%
59	Texas Gas Service Company	2,471,770	**20.00%**	Texas Gas Service Company	849	**23.96%**
60	ONE Gas Inc.	2,595,363	21.00%	ONE Gas Inc.	565	15.95%
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	$12,358,860	100%	Total	$3,543	100%

Schedule G-23

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CONSERVATION PROGRAM REIMBURSEMENT

NOT USED

LINE NO.	DESCRIPTION	REFERENCE	ACCOUNT	RECORDED TEST YEAR	ADJUSTMENT TO REMOVE ALL TEST YEAR CONSERVATION EXPENSES	OTHER ADJUSTMENTS	TOTAL ADJUSTMENTS	ADJUSTED TEST YEAR
				(a)	(b)	(c)	(d)	(e)

SCHEDULE G-24

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PIPELINE INTEGRITY EXPENSE

LINE NO.	DESCRIPTION	AMOUNT
		(a)
1	Total Expense for Planned Testing 2018 through 2023	$1,935,359
2	Number of Years to Levelize Expense	7
3	Levelized Pipeline Integrity Expense	$276,480
4	Test Year Pipeline Integrity Expense	0
5	Adjustment to Test Year	$276,480

Source: SCH G-24 CGSA PIT Expense.xlsx

SCHEDULE G-25

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

HURRICANE HARVEY EXPENSE

LINE NO.	DESCRIPTION	AMOUNT
		(a)
1	Total Hurricane Harvey Expense	$714,389
2	Number of Years to Levelize Expense	6
3	Levelized Hurricane Harvey Expense	$119,065
4	Test Year Hurricane Harvey Expense	0
5	Adjustment to Test Year	$119,065

Source: SCH G-25 CGSA Hurricane Harvey Expenses.xlsx

STUDY SUMMARY

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY SUMMARY

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Customer Costs	$ 100,107,489	$ 94,115,788	$ 5,406,893	$ 42,666	$ 491,970	$ 45,529	$ 4,642
2	Demand Costs	$ 25,170,760	$ 17,551,845	$ 5,126,797	$ 499,815	$ 1,719,945	$ 224,654	$ 47,705
3	Commodity Costs	$ 772,623	$ 416,526	$ 255,340	$ 28,300	$ 61,897	$ 5,225	$ 5,336
4	Cost of Service Before Revenue Credits	$ 126,050,873	$ 112,084,159	$ 10,789,030	$ 570,781	$ 2,273,812	$ 275,408	$ 57,683
5	Revenues Credited to Cost of Service (1)	$ 5,310,492	$ 4,909,627	$ 327,120	$ 13,151	$ 52,938	$ 6,330	$ 1,325
6	Total Cost of Service	$ 120,740,381	$ 107,174,531	$ 10,461,910	$ 557,630	$ 2,220,873	$ 269,078	$ 56,358
7	Revenue at Current Rates	$ 103,693,715	$ 80,613,997	$ 18,406,825	$ 1,224,869	$ 2,965,123	$ 375,105	$ 107,796
8	Revenue Deficiency	$ 17,046,666	$ 26,560,535	$ (7,944,915)	$ (667,238)	$ (744,250)	$ (106,028)	$ (51,438)
9	Revenue-to-Cost Ratios:							
10	Current Revenue	0.8648	0.7630	1.7364	2.1690	1.3273	1.3850	1.8917
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge, special contract, and other revenue are used to offset each class' cost of service. Service charge revenue is directly assigned to classes and is included in the revenue credit on line 5. Allocation of the remaining revenues to be credited is based on each class' cost of service relative to the total cost of service on line 4. The components of the total revenue credit are as follows:

Service Charges	$ 2,415,023
Special Contract	$ 2,872,331
Irrigation	$ 20,483
Unmetered Service	$ 2,655
	$ 5,310,492

STUDY SUMMARY FOR REV. ALLOC.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY SUMMARY FOR REVENUE ALLOCATION

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Customer Costs	$ 100,107,489	$ 94,115,788	$ 5,406,893	$ 42,666	$ 537,499	$ 4,642
2	Demand Costs	$ 25,170,760	$ 17,551,845	$ 5,126,797	$ 499,815	$ 1,944,599	$ 47,705
3	Commodity Costs	$ 772,623	$ 416,526	$ 255,340	$ 28,300	$ 67,122	$ 5,336
4	Cost of Service Before Revenue Credits	$ 126,050,873	$ 112,084,159	$ 10,789,030	$ 570,781	$ 2,549,220	$ 57,683
5	Revenues Credited to Cost of Service	$ 5,310,492	$ 4,909,627	$ 327,120	$ 13,151	$ 59,269	$ 1,325
6	Total Cost of Service	$ 26,044,857	$ 107,174,531	$ 10,461,910	$ 557,630	$ 2,489,951	$ 56,358
7	Revenue at Current Rates	$ 103,693,715	$ 80,613,997	$ 18,406,825	$ 1,224,869	$ 3,340,229	$ 107,796
8	Revenue Deficiency	$ 17,046,666	$ 26,560,535	$ (7,944,915)	$ (667,238)	$ (850,278)	$ (51,438)
9	Revenue-to-Cost Ratios						
10	Current Revenue	0.8648	0.7630	1.7364	2.1690	1.3335	1.8917
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
	Customer and Demand Costs Per Bill		$ 31.65	$ 60.60	$ 775.07	$ 158.01	$ 623.18
	Commodity Cost Per Cff	$ 0.0039					

CLASSIFIED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	$ 57,564	$ 43,115	$ 14,360	$ 89
2	302	Franchises and Consents	NONINTPLT	$ 393,474	$ 294,710	$ 98,157	$ 607
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 753,928	$ 564,688	$ 188,077	$ 1,163
4		Total Intangible Plant		$ 1,204,966	$ 902,514	$ 300,594	$ 1,858
5							
6		Transmission Plant					
7	365	Land and Land Rights	DEM	$ 92,083	$ -	$ 92,083	$ -
8	366	Meas. and Reg. Station Structures	DEM	$ 2,346	$ -	$ 2,346	$ -
9	367	Transmission Mains	DEM	$ 12,223,339	$ -	$ 12,223,339	$ -
10	368	Compression Station Equipment	DEM	$ -	$ -	$ -	$ -
11	369	Measuring and Reg. Station Equipment	DEM	$ 2,390,734	$ -	$ 2,390,734	$ -
12	371	Other Equipment	DEM	$ 45,840	$ -	$ 45,840	$ -
13		Total Transmission Plant		$ 14,754,342	$ -	$ 14,754,342	$ -
14							
15		Distribution Plant					
16	374	Land & Land Rights	DIS376-379	$ 5,837,437	$ 3,545,359	$ 2,287,335	$ 4,743
17	375	Structures and Improvements	DIS376-379	$ 60,083	$ 36,491	$ 23,543	$ 49
18	376	Distribution Mains	MAINS	$ 340,592,534	$ 216,872,700	$ 123,719,834	$ -
19	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
20	378	Meas. & Reg. Sta. Equip.- General	DEM	$ 13,797,566	$ -	$ 13,797,566	$ -
21	378	Odorization Tank	COM	$ 693,072	$ -	$ -	$ 693,072
22	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 2,400,890	$ -	$ 2,400,890	$ -
23	379	Odorization Tank	COM	$ 290,146	$ -	$ -	$ 290,146
24	380	Services	CUS	$ 185,624,492	$ 185,624,492	$ -	$ -
25	381	Meters	CUS	$ 65,333,909	$ 65,333,909	$ -	$ -
26	382	Meter Installations	CUS	$ 6,007	$ 6,007	$ -	$ -
27	383	House Regulators	CUS	$ 9,113,503	$ 9,113,503	$ -	$ -
28	385	Meas. & Reg. Sta. Equipment - Industrial	DEM	$ 13,847,802	$ -	$ 13,847,802	$ -
29	385	Odorization Tank	COM	$ 47,838	$ -	$ -	$ 47,838

CLASSIFIED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
30	386	Other Property - Customer Premises	CUS	$ 1,063,249	$ 1,063,249	$ -	$ -
31	387	Other Equipment		$ 0	$ -	$ -	$ -
32		Total Distribution Plant		$ 638,708,527	$ 481,595,709	$ 156,076,970	$ 1,035,847
33							
34		General Plant					
35	389	Land & Land Rights	GENPLT	$ 294,263	$ 282,238	$ 11,945	$ 79
36	390	Structures & Improvements	GENPLT	$ 8,645,712	$ 7,034,679	$ 1,600,412	$ 10,622
37	391	Office Furniture and Equipment	GENPLT	$ 30,337,107	$ 29,607,574	$ 724,724	$ 4,810
38	392	Transportation Equipment	GENPLT	$ 14,770,453	$ 11,137,141	$ 3,609,358	$ 23,954
39	393	Stores Equipment	GENPLT	$ 8,809	$ 6,642	$ 2,153	$ 14
40	394	Tools, Shop & Garage	GENPLT	$ 7,873,507	$ 5,939,036	$ 1,921,717	$ 12,754
41	394	Odorization Tank	COM	$ 14,329	$ -	$ -	$ 14,329
42	396	Major Work Equipment	GENPLT	$ 1,959,844	$ 1,477,752	$ 478,914	$ 3,178
43	397	Communication Equipment	GENPLT	$ 19,159,094	$ 14,572,824	$ 4,556,032	$ 30,237
44	398	Miscellaneous General Plant	GENPLT	$ 130,360	$ 98,293	$ 31,855	$ 211
45		Total General Plant		$ 83,193,478	$ 70,156,179	$ 12,937,109	$ 100,190
46							
47		Total Plant in Service		$ 737,861,313	$ 552,654,402	$ 184,069,015	$ 1,137,896

CLASSIFIED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
48							
49		Depreciation & Amortization Reserve					
50		Intangible Plant	NONINTPLT	$ (1,178,119)	$ (882,405)	$ (293,897)	$ (1,817)
51		Transmission Plant	DEM	$ (3,636,481)	$ -	$ (3,636,481)	$ -
52		Distribution Plant	DISPLTRES	$ (147,644,682)	$ (112,986,265)	$ (34,802,441)	$ 144,024
53		General Plant	GENPLTRES	$ (29,723,482)	$ (24,689,306)	$ (5,001,935)	$ (32,241)
54		Total Depreciation & Amortization Reserve		$ (182,182,765)	$ (138,557,976)	$ (43,734,754)	$ 109,966
55							
56		Net Plant in Service		$ 555,678,548	$ 414,096,426	$ 140,334,261	$ 1,247,862
57							
58		Customer Deposits	CUS	$ (7,853,752)	$ (7,853,752)	$ -	$ -
59							
60		Customer Advances	MAINS/SVCS	$ (21,363,984)	$ (16,341,059)	$ (5,022,925)	$ -
61							
62		Accumulated Deferred Income Taxes	TOTPLT	$ (80,421,556)	$ (60,235,340)	$ (20,062,194)	$ (124,022)
63							
64		Materials and Supplies	TOTPLT	$ 4,272,141	$ 3,199,812	$ 1,065,741	$ 6,588
65							
66		Prepayments	OPEXP	$ 2,581,813	$ 2,160,997	$ 392,121	$ 28,695
67							
68		Pension & FAS 106 Regulatory Asset	OPEXP	$ 25,045,624	$ 20,963,380	$ 3,803,884	$ 278,360
69							
70		DIMP Deferrals	OPEXP	$ 528,827	$ 442,632	$ 80,317	$ 5,877
71							
72		Cash Working Capital	OPEXP	$ (4,999,624)	$ (4,184,724)	$ (759,334)	$ (55,566)
73							
74		Total Rate Base		$ 473,468,036	$ 352,248,372	$ 119,831,871	$ 1,387,793

CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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	850-66	Transmission Expenses	DEM	$ 972,153	$ -	$ 972,153	$ -
3	870	Operation Supervision & Engineering	DIS871-879	$ 735,005	$ 600,373	$ 114,286	$ 20,346
4	870	Odorization	COM	$ 814	$ -	$ -	$ 814
5	871	Distribution Load Dispatch	COM	$ 260,199	$ -	$ -	$ 260,199
6	874	Mains and Services Expenses	MAINS/SVCS	$ 4,244,625	$ 3,246,664	$ 997,962	$ -
7	874	Odorization	COM	$ 964	$ -	$ -	$ 964
8	875	Measuring & Reg. Station Expense - General	DEM	$ 391,310	$ -	$ 391,310	$ -
9	875	Odorization	COM	$ 58,361	$ -	$ -	$ 58,361
10	876	Meas. & Reg. Station Expense.- Industrial	DEM	$ 68,073	$ -	$ 68,073	$ -
11	877	Meas. & Regulating Station Exp.- City Gate	DEM	$ 4,260	$ -	$ 4,260	$ -
12	878	Meter and House Regulator Expenses	CUS	$ 4,347,173	$ 4,347,173	$ -	$ -
13	879	Customer Installation Expenses	CUS	$ 84,335	$ 84,335	$ -	$ -
14	880	Other Expenses	CUS	$ 1,446,075	$ 1,446,075	$ -	$ -
15	880	Odorization	COM	$ 51	$ -	$ -	$ 51
16	881	Rents	DIS871-879	$ (188,295)	$ (153,805)	$ (29,278)	$ (5,212)
17		Total Transmission & Distribution Oper. Exp.		$ 12,425,104	$ 9,570,816	$ 2,518,766	$ 335,522
18							
19		Distribution Maintenance Expenses					
20	885	Maintenance Supervision and Engineering	DIS887-893	$ 72	$ 41	$ 31	$ -
21	886	Structures and Improvements	DIS887-893	$ 362,515	$ 204,641	$ 157,874	$ -
22	887	Maintenance of Mains	MAINS	$ 3,313,703	$ 2,110,004	$ 1,203,699	$ -
23	889	Maint. of Meas. & Reg. Sta. Equip.- General	DEM	$ 395,845	$ -	$ 395,845	$ -
24	889	Odorization	COM	$ 17,985	$ -	$ -	$ 17,985
25	890	Maint. of Meas. & Reg. Sta. Equip. - Industrial	DEM	$ 585,505	$ -	$ 585,505	$ -
26	891	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 19,823	$ -	$ 19,823	$ -

CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
27	892	Maintenance of Services	CUS	$ 740,925	$ 740,925	$ -	$ -
28	893	Main. of Meters & House Regulators	CUS	$ 7,092	$ 7,092	$ -	$ -
29	894	Maintenance of Other Equipment	DIS887-893	$ -	$ -	$ -	$ -
30		Total Distribution Maintenance Expenses		$ 5,443,464	$ 3,062,703	$ 2,362,777	$ 17,985
31							
32		Total Operations & Maintenance Expenses		$ 17,868,568	$ 12,633,519	$ 4,881,542	$ 353,507
33							
34		Customer Accounts Expenses					
35	901	Supervision	CUS	$ 154,499	$ 154,499	$ -	$ -
36	902	Meter Reading Expense	CUS	$ 1,351,191	$ 1,351,191	$ -	$ -
37	903	Customer Accounting	CUS	$ 4,115,966	$ 4,115,966	$ -	$ -
38	904	Bad Debts (includes gross up)	CUS	$ 677,271	$ 677,271	$ -	$ -
39	905	Miscellaneous Customer Accounts Expenses	CUS	$ 342,471	$ 342,471	$ -	$ -
40		Total Customer Accounts Expenses		$ 6,641,399	$ 6,641,399	$ -	$ -
41							
42		Customer Service Expenses					
43	907	Supervision	CUS	$ -	$ -	$ -	$ -
44	908	Customer Assistance	CUS	$ 743,891	$ 743,891	$ -	$ -
45	909	Informational and Instructional Advertising	CUS	$ 93,297	$ 93,297	$ -	$ -
46		Total Customer Service Expenses		$ 837,188	$ 837,188	$ -	$ -
47							
48		Sales and Advertising Expenses					
49	912	Demonstrating and Selling	CUS	$ -	$ -	$ -	$ -
50	913	Advertising	CUS	$ 23,611	$ 23,611	$ -	$ -
51		Total Sales and Advertising Expenses		$ 23,611	$ 23,611	$ -	$ -
52							

CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
53		Administrative & General Expenses					
54	921-32	Administrative & General Expenses	ADMINGEN	$ 26,311,246	$ 23,122,526	$ 2,967,828	$ 220,893
55		Total Administrative & General Expenses		$ 26,311,246	$ 23,122,526	$ 2,967,828	$ 220,893
56							
57		Depreciation and Amortization Expense					
58	301-303	Intangible Plant	PLT301-03	$ 32,365	$ 24,241	$ 8,074	$ 50
59	365	Land and Land Rights	DEM	$ 32	$ -	$ 32	$ -
60	366	Meas. and Reg. Station Structures	PLT366	$ 95	$ -	$ 95	$ -
61	367	Transmission Mains	PLT367	$ 213,908	$ -	$ 213,908	$ -
62	368	Compression Station Equipment	PLT368	$ -	$ -	$ -	$ -
63	369	Measuring and Reg. Station Equipment	PLT369	$ 50,155	$ -	$ 50,155	$ -
64	371	Other Equipment	PLT371	$ 1,201	$ -	$ 1,201	$ -
65	375	Structures and Improvements	PLT375	$ 1,136	$ 690	$ 445	$ 1
66	376	Mains	PLT376	$ 7,674,509	$ 4,886,752	$ 2,787,756	$ -
67	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
68	378	Meas. & Reg. Sta. Equipment - General	PLT378	$ 296,057	$ -	$ 296,057	$ -
69	378	Odorization Tank	COM	$ 14,693	$ -	$ -	$ 14,693
70	379	Meas. & Reg. Sta. Equipment - City Gate	PLT379	$ 40,742	$ -	$ 40,742	$ -
71	379	Odorization Tank	COM	$ 4,903	$ -	$ -	$ 4,903
72	380	Services	PLT380	$ 4,742,152	$ 4,742,152	$ -	$ -
73	381	Meters	PLT381	$ 2,639,514	$ 2,639,514	$ -	$ -
74	382	Meter Installations	PLT382	$ -	$ -	$ -	$ -
75	383	House Regulators	PLT383	$ 232,452	$ 232,452	$ -	$ -
76	385	Meas. & Reg. Sta. Equip. - Industrial	PLT385	$ 297,860	$ -	$ 297,860	$ -
77	385	Odorization Tank	COM	$ 1,029	$ -	$ -	$ 1,029
78	386	Other Property - Customer Premises	PLT386	$ (1,701)	$ (1,701)	$ -	$ -

CLASSIFIED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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)
79	387	Other Equipment		$ 0	$ -	$ -	$ -
80	389-98	General Plant	GENDEP	$ 5,110,034	$ 4,509,586	$ 595,539	$ 4,909
81	4073	Pension & FAS 106 Amortization Expense	OPEXP	$ 330,846	$ 276,921	$ 50,248	$ 3,677
82		Total Depreciation and Amortization Expense		$ 21,681,983	$ 17,310,608	$ 4,342,113	$ 29,262
83							
84		Taxes Other Than Income					
85	408	Payroll and Other	OPEXP	$ 2,624,541	$ 2,196,761	$ 398,610	$ 29,169
86	408	Ad Valorem	TOTPLT	$ 4,385,203	$ 3,284,495	$ 1,093,945	$ 6,763
87	408	Revenue Related (includes gross up)	CUS	$ 141,127	$ 141,127	$ -	$ -
88		Total Taxes Other Than Income		$ 7,150,871	$ 5,622,382.69	$ 1,492,555.87	$ 35,932.08
89							
90	431	Interest on Customer Deposits	CUS	$ 150,792	$ 150,792	$ -	$ -
91							
92		Required Return	RB	$ 37,529,690	$ 27,921,150	$ 9,498,536	$ 110,004
93		Income Taxes	RB	$ 7,855,526	$ 5,844,315	$ 1,988,186	$ 23,026
94		Total Cost of Service Before Revenue Credits		$ 126,050,873	$ 100,107,489	$ 25,170,760	$ 772,623

CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**CUS**	**Customer Factor**		**1.00000**	**0.00000**	**0.00000**
2							
3		**DEM**	**Demand Factor**		**0.00000**	**1.00000**	**0.00000**
4							
5		**COM**	**Commodity Factor**		**0.00000**	**0.00000**	**1.00000**
6							
7		**DEM-COM**	**Demand and Commodity Factor**		**0.00000**	**0.50000**	**0.50000**
8							
9			Total Transmission Plant	$ 14,754,342	$ -	$ 14,754,342	$ -
10			Total Distribution Plant	$ 638,708,527	$ 481,595,709	$ 156,076,970	$ 1,035,847
11			Total General Plant	$ 83,193,478	$ 70,156,179	$ 12,937,109	$ 100,190
12			Total Non-Intangible Plant	$ 736,656,347	$ 551,751,889	$ 183,768,421	$ 1,136,037
13		**NONINTPLT**	**Non-Intangible Plant Factor**	**1.00000**	**0.74899**	**0.24946**	**0.00154**
14							
15	376		Distribution Mains	$ 340,592,534	$ 216,872,700	$ 123,719,834	$ -
16	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
17	378		Meas. & Reg. Sta. Equip.- General	$ 13,797,566	$ -	$ 13,797,566	$ -
18	379		Meas. & Reg. Sta. Equip.- City Gate	$ 2,691,036	$ -	$ 2,400,890	$ 290,146
19			Total Accounts 376-379	$ 357,081,136	$ 216,872,700	$ 139,918,290	290,146
20		**DIS376-379**	**Accounts 376-379 Factor**	**1.00000**	**0.60735**	**0.39184**	**0.00081**
21							
22	376		Mains	$ 340,592,534	$ 216,872,700	$ 123,719,834	$ -
23		**MAINS**	**Distribution Mains Factor**	**1.00000**	**0.63675**	**0.36325**	**0.00000**
24							
25	376/380		Mains and Services	$ 526,217,025	$ 402,497,192	$ 123,719,834	$ -
26		**MAINS/SVCS**	**Mains and Services Factor**	**1.00000**	**0.76489**	**0.23511**	**0.00000**

CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
27							
28	374-87		Total Distribution Plant	$ 638,708,527	$ 481,595,709	$ 156,076,970	$ 1,035,847
29		**DISPLT**	**Distribution Plant Factor**	**1.00000**	**0.75401**	**0.24436**	**0.00162**
30							
31			General Plant Reserve	$ (29,723,482)	$ (24,689,306)	$ (5,001,935)	$ (32,241)
32		**GENPLTRES**	**General Plant Reserve Factor**	**1.00000**	**0.83063**	**0.16828**	**0.00108**
33							
34			Total Plant	$ 737,861,313	$ 552,654,402	$ 184,069,015	$ 1,137,896
35		**TOTPLT**	**Total Plant Factor**	**1.00000**	**0.74899**	**0.24946**	**0.00154**
36							
37	374		Land & Land Rights	$ (9,695)	$ (5,888)	$ (3,799)	$ (8)
38	375		Structures and Improvements	$ 4,229	$ 2,569	$ 1,657	$ 3
39	376		Distribution Mains	$ (72,946,895)	$ (46,449,022)	$ (26,497,873)	$ -
40	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
41	378		Meas. & Reg. Station Equip.- General	$ (2,833,020)	$ -	$ (2,833,020)	$ -
42	378		Odorization Tank	$ 104,970	$ -	$ -	$ 104,970
43	379		Meas. & Reg. Station Equip.- City Gate	$ (735,409)	$ -	$ (735,409)	$ -
44	379		Odorization Tank	$ 39,916	$ -	$ -	$ 39,916
45	380		Services	$ (37,018,022)	$ (37,018,022)	$ -	$ -
46	381		Meters	$ (24,888,362)	$ (24,888,362)	$ -	$ -
47	382		Meter Installations	$ (10,203)	$ (10,203)	$ -	$ -
48	383		House Regulators	$ (3,976,993)	$ (3,976,993)	$ -	$ -
49	385		Meas. & Reg. Sta. Equipment - Industrial	$ (4,320,871)	$ -	$ (4,320,871)	$ -
50	386		Other Property - Customer Premises	$ (1,054,327)	$ (640,344)	$ (413,126)	$ (857)
51	387		Other Equipment	$ -			
52			Total Distribution Plant Reserve	$ (147,644,682)	$ (112,986,265)	$ (34,802,441)	$ 144,024

CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
53		**DISPLTRES**	**Distribution Plant Reserve**	**1.00000**	**0.76526**	**0.23572**	**(0.00098)**
54							
55			Total Operations and Maintenance Expenses	$ 17,868,568	$ 12,633,519	$ 4,881,542	$ 353,507
56			Total Customer Accounts Expenses	$ 6,641,399	$ 6,641,399	$ -	$ -
57			Total Customer Service Expenses	$ 837,188	$ 837,188	$ -	$ -
58			Total Sales and Advertising Expenses	$ 23,611	$ 23,611	$ -	$ -
59			Administrative and General Expenses	$ 26,311,246	$ 23,122,526	$ 2,967,828	$ 220,893
60			Total Operating Expenses	$ 51,682,012	$ 43,258,242	$ 7,849,370	$ 574,399
61		**OPEXP**	**Operating Expense Factor**	**1.00000**	**0.83701**	**0.15188**	**0.01111**
62							
63	871		Distribution Load Dispatch	$ 260,199	$ -	$ -	$ 260,199
64	874		Mains and Services Expenses	$ 4,244,625	$ 3,246,664	$ 997,962	$ -
65	875		Measuring & Reg. Station Expense - General	$ 391,310	$ -	$ 391,310	$ -
66	876		Meas. & Reg. Station Expense.- Industrial	$ 68,073	$ -	$ 68,073	$ -
67	877		Meas. & Regulating Station Exp.- City Gate	$ 4,260	$ -	$ 4,260	$ -
68	878		Meter and House Regulator Expenses	$ 4,347,173	$ 4,347,173	$ -	$ -
69	879		Customer Installation Expenses	$ 84,335	$ 84,335	$ -	$ -
70			Total Accounts 871-879	$ 9,399,975	$ 7,678,172	$ 1,461,604	$ 260,199
71		**DIS871-879**	**Accounts 871-879 Factor**	**1.00000**	**0.81683**	**0.15549**	**0.02768**
72							
73	887		Maintenance of Mains	$ 3,313,703	$ 2,110,004	$ 1,203,699	$ -
74	889		Maint. of Meas. & Reg. Sta. Equip.- General	$ 395,845	$ -	$ 395,845	$ -
75	890		Maint. of Meas. & Reg. Sta. Equip. - Industrial	$ 585,505	$ -	$ 585,505	$ -
76	891		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 19,823	$ -	$ 19,823	$ -
77	892		Maintenance of Services	$ 740,925	$ 740,925	$ -	$ -
78	893		Main. of Meters & House Regulators	$ 7,092	$ 7,092	$ -	$ -

CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
79			Total Accounts 887-893	$ 5,062,892	$ 2,858,021	$ 2,204,871	$ -
80		**DIS887-893**	**Accounts 887-893 Factor**	**1.00000**	**0.56450**	**0.43550**	**0.00000**
81							
82			Total Operations and Maintenance Expenses	$ 17,868,568	$ 12,633,519	$ 4,881,542	$ 353,507
83			Total Customer Accounts Expenses	$ 6,641,399	$ 6,641,399	$ -	-
84			Total Customer Service Expenses	$ 837,188	$ 837,188	$ -	-
85			Total Sales and Advertising Expenses	$ 23,611	$ 23,611	$ -	$ -
86			Total Operating Exp. Without A&G Expenses	$ 25,370,766	$ 20,135,717	$ 4,881,542	$ 353,507
87		**NONAGOPEXP**	**Non-A&G Operating Expenses Factor**	**1.00000**	**0.79366**	**0.19241**	**0.01393**
88							
89	920-932		Administrative and General Expenses	$ 26,311,246	$ 23,122,526	$ 2,967,828	$ 220,893
90		**ADMINGEN**	**Administrative and General Expenses Factor**	**1.00000**	**0.87881**	**0.11280**	**0.00840**
91							
92	366		Meas. and Reg. Station Structures	$ 2,346	$ -	$ 2,346	$ -
93		**PLT366**	**Measuring and Reg. Station Structures Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
94							
95	367		Transmission Mains	$ 12,223,339	$ -	$ 12,223,339	$ -
96		**PLT367**	**Transmission Mains**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
97							
98	368		Compression Station Equipment	$ -	$ -	$ -	$ -
99		**PLT368**	**Compression Station Equipment Factor**	**0.00000**	**0.00000**	**0.00000**	**0.00000**
100							
101	369		Measuring and Reg. Station Equipment	$ 2,390,734	$ -	$ 2,390,734	$ -
102		**PLT369**	**Measuring & Reg, Station Equipment Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
103							
104	371		Other Equipment	$ 45,840	$ -	$ 45,840	$ -

CLASSIFICATION FACTORS

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CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
105		**PLT371**	**Other Equipment Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
106							
107	375		Structures and Improvements	$ 60,083	$ 36,491	$ 23,543	$ 49
108		**PLT375**	**Structures and Improvements Factor**	**1.00000**	**0.60735**	**0.39184**	**0.00081**
109							
110	376		Distribution Mains	$ 340,592,534	$ 216,872,700	$ 123,719,834	$ -
111		**PLT376**	**Distribution Mains Factor**	**1.00000**	**0.63675**	**0.36325**	**0.00000**
112							
113	378		Meas. & Reg. Sta. Equip.- General	$ 13,797,566	$ -	$ 13,797,566	$ -
114		**PLT378**	**Meas. & Reg. Station Equip. - General Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
115							
116	379		Meas. & Reg. Sta. Equip.- City Gate	$ 2,400,890	$ -	$ 2,400,890	$ -
117		**PLT379**	**Meas. & Reg. Station Equip. - City Gate Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
118							
119	380		Services	$ 185,624,492	$ 185,624,492	$ -	$ -
120		**PLT380**	**Services Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
121							
122	381		Meters	$ 65,333,909	$ 65,333,909	$ -	$ -
123		**PLT381**	**Meters Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
124							
125	382		Meter Installations	$ 6,007	$ 6,007	$ -	$ -
126		**PLT382**	**Meter Installations Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
127							
128	383		House Regulators	$ 9,113,503	$ 9,113,503	$ -	$ -
129		**PLT383**	**House Regulators Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
130							

CLASSIFICATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
131	385		Meas. & Reg. Sta. Equipment - Industrial	$ 13,847,802	$ -	$ 13,847,802	$ -
132		**PLT385**	**Meas. & Reg. Sta. Equip.-Industrial Factor**	**1.00000**	**0.00000**	**1.00000**	**0.00000**
133							
134	386		Other Property - Customer Premises	$ 1,063,249	$ 1,063,249	$ -	$ -
135		**PLT386**	**Other Property-Customer Premises Factor**	**1.00000**	**1.00000**	**0.00000**	**0.00000**
136							
137	301-03		Intangible Plant	$ 1,204,966	$ 902,514	$ 300,594	$ 1,858
138		**PLT301-03**	**Intangible Plant**	**1.00000**	**0.74899**	**0.24946**	**0.00154**
139							
140	389-98		General Plant Depreciation Expense	$ 5,110,034	$ 4,509,586	$ 595,539	$ 4,909
141		**GENDEP**	**General Plant Depreciation Expense Factor**	**1.00000**	**0.88250**	**0.11654**	**0.00096**
142							
143			Rate Base	$ 473,468,036	$ 352,248,372	$ 119,831,871	$ 1,387,793
144		**RB**	**Rate Base Factor**	**1.00000**	**0.74397**	**0.25309**	**0.00293**

ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	301-303	**Intangible Plant**								
2		Customer	CUS	$ 902,514	$ 856,319	$ 42,191	$ 170	$ 3,559	$ 254	$ 20
3		Demand	DEM	$ 300,594	$ 222,215	$ 52,742	$ 5,142	$ 17,694	$ 2,311	$ 491
4		Commodity	COM	$ 1,858	$ 1,002	$ 614	$ 68	$ 149	$ 13	$ 13
		Total Intangible Plant		$ 1,204,966	$ 1,079,536	$ 95,547	$ 5,380	$ 21,402	$ 2,577	$ 524
5	365-371	**Transmission Plant**								
6		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7		Demand	DEM	$ 14,754,342	$ 10,907,177	$ 2,588,772	$ 252,381	$ 868,485	$ 113,439	$ 24,088
8		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Total Transmission Plant		$ 14,754,342	$ 10,907,177	$ 2,588,772	$ 252,381	$ 868,485	$ 113,439	$ 24,088
10		**Distribution Plant**								
11	374	**Land & Land Rights**								
12		Customer	CUS	$ 3,545,359	$ 3,363,893	$ 165,741	$ 667	$ 13,982	$ 996	$ 80
13		Demand	DEM	$ 2,287,335	$ 1,690,917	$ 401,332	$ 39,126	$ 134,639	$ 17,586	$ 3,734
14		Commodity	COM	$ 4,743	$ 2,557	$ 1,568	$ 174	$ 380	$ 32	$ 33
15		Total Land & Land Rights		$ 5,837,437	$ 5,057,367	$ 568,640	$ 39,967	$ 149,001	$ 18,614	$ 3,847
16	375	**Structures and Improvements**								
17		Customer	CUS	$ 36,491	$ 34,623	$ 1,706	$ 7	$ 144	$ 10	$ 1
18		Demand	DEM	$ 23,543	$ 17,404	$ 4,131	$ 403	$ 1,386	$ 181	$ 38
19		Commodity	COM	$ 49	$ 26	$ 16	$ 2	$ 4	$ 0	$ 0
20		Total Structures and Improvements		$ 60,083	$ 52,054	$ 5,853	$ 411	$ 1,534	$ 192	$ 40
21	376	**Distribution Mains**								
22		Customer	CUS	$ 216,872,700	$ 205,772,242	$ 10,138,517	$ 40,823	$ 855,288	$ 60,931	$ 4,899
23		Demand	DEM	$ 123,719,834	$ 91,460,140	$ 21,707,672	$ 2,116,294	$ 7,282,518	$ 951,220	$ 201,989
24		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Total Distribution Mains		$ 340,592,534	$ 297,232,382	$ 31,846,189	$ 2,157,117	$ 8,137,806	$ 1,012,151	$ 206,889
26	377	**Compressor Station Equipment**								
27		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	378	**Meas. & Reg. Sta. Equip. - General**								
32		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33		Demand	DEM	$ 13,797,566	$ 10,199,879	$ 2,420,898	$ 236,015	$ 812,166	$ 106,083	$ 22,526
34		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
35		Total Meas. & Reg. Sta. Equip.- Gen.		$ 13,797,566	$ 10,199,879	$ 2,420,898	$ 236,015	$ 812,166	$ 106,083	$ 22,526
36	378	**Odorization Tank**								
37		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Commodity	COM	$ 693,072	$ 373,639	$ 229,049	$ 25,386	$ 55,524	$ 4,687	$ 4,786
40		Total Odorization Tank		$ 693,072	$ 373,639	$ 229,049	$ 25,386	$ 55,524	$ 4,687	$ 4,786
41	379	**Meas. & Reg. Station - City Gate**								
42		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43		Demand	DEM	$ 2,400,890	$ 1,774,863	$ 421,256	$ 41,069	$ 141,324	$ 18,459	$ 3,920
44		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45		Total Meas. & Reg. Equip.-City Gate		$ 2,400,890	$ 1,774,863	$ 421,256	$ 41,069	$ 141,324	$ 18,459	$ 3,920
46	379	**Odorization Tank**								
47		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49		Commodity	COM	$ 290,146	$ 156,419	$ 95,888	$ 10,628	$ 23,244	$ 1,962	$ 2,004
50		Total Odorization Tank		$ 290,146	$ 156,419	$ 95,888	$ 10,628	$ 23,244	$ 1,962	$ 2,004
51	380	**Services**								
52		Customer	SERCUS	$ 185,624,492	$ 175,065,817	$ 9,554,338	$ 49,774	$ 877,158	$ 72,095	$ 5,312
53		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Total Services		$ 185,624,492	$ 175,065,817	$ 9,554,338	$ 49,774	$ 877,158	$ 72,095	$ 5,312
56	381	**Meters**								
57		Customer	METCUS	$ 65,333,909	$ 59,082,872	$ 5,449,115	$ 87,355	$ 624,774	$ 79,787	$ 10,006
58		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Total Meters		$ 65,333,909	$ 59,082,872	$ 5,449,115	$ 87,355	$ 624,774	$ 79,787	$ 10,006
61	382	**Meter Installations**								
62		Customer	METCUS	$ 6,007	$ 5,433	$ 501	$ 8	$ 57	$ 7	$ 1
63		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65		Total Meter Installations		$ 6,007	$ 5,433	$ 501	$ 8	$ 57	$ 7	$ 1
66	383	**House Regulators**								
67		Customer	REGCUS	$ 9,113,503	$ 7,946,452	$ 1,011,336	$ 16,780	$ 120,383	$ 16,669	$ 1,882
68		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ALLOCATED RATE BASE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
70		Total House Regulators		$ 9,113,503	$ 7,946,452	$ 1,011,336	$ 16,780	$ 120,383	$ 16,669	$ 1,882
71	385	**Meas. & Reg. Sta. Equipment - Industrial**								
72		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73		Demand	NRDEM	$ 13,847,802	$ -	$ 9,318,239	$ 908,441	$ 3,126,095	$ 408,321	$ 86,706
74		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75		Total Meas. & Reg. Sta. Equip.- Ind.		$ 13,847,802	$ -	$ 9,318,239	$ 908,441	$ 3,126,095	$ 408,321	$ 86,706
76	385	**Odorization Tank**								
77		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79		Commodity	COM	$ 47,838	$ 25,790	$ 15,810	$ 1,752	$ 3,832	$ 324	$ 330
80		Total Odorization Tank		$ 47,838	$ 25,790	$ 15,810	$ 1,752	$ 3,832	$ 324	$ 330
81	386	**Other Prop.-Customer Premises**								
82		Customer	CUS	$ 1,063,249	$ 1,008,828	$ 49,706	$ 200	$ 4,193	$ 299	$ 24
83		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85		Total Other Prop.- Cust. Premises		$ 1,063,249	$ 1,008,828	$ 49,706	$ 200	$ 4,193	$ 299	$ 24
86	387	**Other Equipment**								
87		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
91		**Total Distribution Plant**								
92		Customer		$ 481,595,709	$ 452,280,159	$ 26,370,959	$ 195,614	$ 2,495,979	$ 230,794	$ 22,204
93		Demand		$ 156,076,970	$ 105,143,204	$ 34,273,527	$ 3,341,347	$ 11,498,128	$ 1,501,850	$ 318,914
94		Commodity		$ 1,035,847	$ 558,431	$ 342,331	$ 37,942	$ 82,985	$ 7,006	$ 7,153
95		Total Distribution Plant		$ 638,708,527	$ 557,981,793	$ 60,986,817	$ 3,574,903	$ 14,077,092	$ 1,739,650	$ 348,272
96		**Total General Plant**								
97		Customer	CUS	$ 70,156,179	$ 66,565,291	$ 3,279,710	$ 13,206	$ 276,677	$ 19,710	$ 1,585
98		Demand	DEM	$ 12,937,109	$ 9,563,784	$ 2,269,923	$ 221,296	$ 761,517	$ 99,467	$ 21,122
99		Commodity	COM	$ 100,190	$ 54,013	$ 33,111	$ 3,670	$ 8,026	$ 678	$ 692
100		Total General Plant		$ 83,193,478	$ 76,183,088	$ 5,582,745	$ 238,172	$ 1,046,220	$ 119,855	$ 23,398
101		**Total Plant in Service**								
102		Customer		$ 552,654,402	$ 519,701,768	$ 29,692,861	$ 208,990	$ 2,776,215	$ 250,758	$ 23,810
103		Demand		$ 184,069,015	$ 125,836,381	$ 39,184,963	$ 3,820,166	$ 13,145,823	$ 1,717,067	$ 364,615
104		Commodity		$ 1,137,896	$ 613,446	$ 376,056	$ 41,680	$ 91,160	$ 7,696	$ 7,858

ALLOCATED RATE BASE

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CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
105		Total Plant in Service		$ 737,861,313	$ 646,151,595	$ 69,253,881	$ 4,070,835	$ 16,013,199	$ 1,975,521	$ 396,283
106		**Depreciation & Amort. Reserve**								
107		**Intangible Plant**								
108		Customer	CUS	$ (882,405)	$ (837,240)	$ (41,251)	$ (166)	$ (3,480)	$ (248)	$ (20)
109		Demand	DEM	$ (293,897)	$ (217,264)	$ (51,567)	$ (5,027)	$ (17,300)	$ (2,260)	$ (480)
110		Commodity	COM	$ (1,817)	$ (979)	$ (600)	$ (67)	$ (146)	$ (12)	$ (13)
111		Total Intangible Plant		$ (1,178,119)	$ (1,055,483)	$ (93,418)	$ (5,260)	$ (20,925)	$ (2,520)	$ (512)
112		**Transmission Plant**								
113		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
114		Demand	DEM	$ (3,636,481)	$ (2,688,276)	$ (638,051)	$ (62,204)	$ (214,054)	$ (27,959)	$ (5,937)
115		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116		Total Transmission Plant		$ (3,636,481)	$ (2,688,276)	$ (638,051)	$ (62,204)	$ (214,054)	$ (27,959)	$ (5,937)
117		**Distribution Plant**								
118		Customer	DISPLTCUS	$ (112,986,265)	$ (106,108,599)	$ (6,186,841)	$ (45,893)	$ (585,577)	$ (54,146)	$ (5,209)
119		Demand	DISPLTDEM	$ (34,802,441)	$ (23,445,100)	$ (7,642,399)	$ (745,062)	$ (2,563,882)	$ (334,886)	$ (71,112)
120		Commodity	COM	$ 144,024	$ 77,644	$ 47,598	$ 5,275	$ 11,538	$ 974	$ 995
121		Total Distribution Plant		$ (147,644,682)	$ (129,476,055)	$ (13,781,642)	$ (785,679)	$ (3,137,921)	$ (388,058)	$ (75,327)
122		**General Plant**								
123		Customer	CUS	$ (24,689,306)	$ (23,425,603)	$ (1,154,193)	$ (4,647)	$ (97,368)	$ (6,936)	$ (558)
124		Demand	DEM	$ (5,001,935)	$ (3,697,691)	$ (877,631)	$ (85,561)	$ (294,429)	$ (38,457)	$ (8,166)
125		Commodity	COM	$ (32,241)	$ (17,382)	$ (10,655)	$ (1,181)	$ (2,583)	$ (218)	$ (223)
126		Total General Plant		$ (29,723,482)	$ (27,140,676)	$ (2,042,479)	$ (91,389)	$ (394,380)	$ (45,612)	$ (8,947)
127		**Total Depr. & Amort. Reserve**								
128		Customer		$ (138,557,976)	$ (130,371,442)	$ (7,382,286)	$ (50,706)	$ (686,425)	$ (61,330)	$ (5,787)
129		Demand		$ (43,734,754)	$ (30,048,331)	$ (9,209,647)	$ (897,854)	$ (3,089,665)	$ (403,563)	$ (85,696)
130		Commodity		$ 109,966	$ 59,283	$ 36,342	$ 4,028	$ 8,810	$ 744	$ 759
131		Total Depr. & Amortization Reserve		$ (182,182,765)	$ (160,360,490)	$ (16,555,591)	$ (944,532)	$ (3,767,280)	$ (464,149)	$ (90,723)
132		**Net Plant in Service**								
133		Customer		$ 414,096,426	$ 389,330,326	$ 22,310,575	$ 158,284	$ 2,089,791	$ 189,427	$ 18,023
134		Demand		$ 140,334,261	$ 95,788,050	$ 29,975,316	$ 2,922,312	$ 10,056,159	$ 1,313,505	$ 278,920
135		Commodity		$ 1,247,862	$ 672,729	$ 412,398	$ 45,708	$ 99,970	$ 8,440	$ 8,618
136		Total Net Plant in Service		$ 555,678,548	$ 485,791,105	$ 52,698,290	$ 3,126,303	$ 12,245,919	$ 1,511,371	$ 305,560
137		**Customer Deposits**								
138		Customer	DEPCUS	$ (7,853,752)	$ (4,634,440)	$ (3,175,747)	$ (35,306)	$ (7,435)	$ (824)	$ -
139		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
140		Commodity	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
141		Total Customer Deposits		$ (7,853,752)	$ (4,634,440)	$ (3,175,747)	$ (35,306)	$ (7,435)	$ (824)	$ -
142		**Customer Advances**								
143		Customer	MSCUS	$ (16,341,059)	$ (15,461,716)	$ (799,514)	$ (3,678)	$ (70,336)	$ (5,401)	$ (415)
144		Demand	DEM	$ (5,022,925)	$ (3,713,207)	$ (881,314)	$ (85,920)	$ (295,664)	$ (38,619)	$ (8,201)
145		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
146		Total Customer Advances		$ (21,363,984)	$ (19,174,923)	$ (1,680,828)	$ (89,598)	$ (366,000)	$ (44,019)	$ (8,615)
147		**Accum. Deferred Income Taxes**								
148		Customer	TPLTCUS	$ (60,235,340)	$ (56,643,741)	$ (3,236,307)	$ (22,778)	$ (302,587)	$ (27,331)	$ (2,595)
149		Demand	TPLTDEM	$ (20,062,194)	$ (13,715,257)	$ (4,270,878)	$ (416,370)	$ (1,432,800)	$ (187,148)	$ (39,740)
150		Commodity	COM	$ (124,022)	$ (66,861)	$ (40,987)	$ (4,543)	$ (9,936)	$ (839)	$ (856)
151		Total Accum. Deferred Inc. Taxes		$ (80,421,556)	$ (70,425,859)	$ (7,548,173)	$ (443,692)	$ (1,745,323)	$ (215,317)	$ (43,192)
152		**Materials and Supplies**								
153		Customer	TPLTCUS	$ 3,199,812	$ 3,009,020	$ 171,919	$ 1,210	$ 16,074	$ 1,452	$ 138
154		Demand	TPLTDEM	$ 1,065,741	$ 728,580	$ 226,877	$ 22,118	$ 76,113	$ 9,942	$ 2,111
155		Commodity	COM	$ 6,588	$ 3,552	$ 2,177	$ 241	$ 528	$ 45	$ 45
156		Total Materials and Supplies		$ 4,272,141	$ 3,741,151	$ 400,973	$ 23,570	$ 92,715	$ 11,438	$ 2,294
157		**Prepayments**								
158		Customer	OPEXPCUS	$ 2,160,997	$ 2,023,400	$ 123,346	$ 1,163	$ 11,764	$ 1,197	$ 128
159		Demand	OPEXPDEM	$ 392,121	$ 256,997	$ 90,926	$ 8,864	$ 30,504	$ 3,984	$ 846
160		Commodity	COM	$ 28,695	$ 15,469	$ 9,483	$ 1,051	$ 2,299	$ 194	$ 198
161		Total Prepayments		$ 2,581,813	$ 2,295,866	$ 223,754	$ 11,079	$ 44,567	$ 5,375	$ 1,172
162		**Pension & FAS 106 Reg. Asset**								
163		Customer	OPEXPCUS	$ 20,963,380	$ 19,628,575	$ 1,196,549	$ 11,284	$ 114,122	$ 11,608	$ 1,242
164		Demand	OPEXPDEM	$ 3,803,884	$ 2,493,070	$ 882,052	$ 85,992	$ 295,912	$ 38,651	$ 8,207
165		Commodity	COM	$ 278,360	$ 150,065	$ 91,993	$ 10,196	$ 22,300	$ 1,883	$ 1,922
166		Total Pen. & FAS 106 Reg. Asset		$ 25,045,624	$ 22,271,710	$ 2,170,595	$ 107,472	$ 432,334	$ 52,142	$ 11,372
167		**DIMP Deferrals**								
168		Customer	TPLTCUS	$ 442,632	$ 416,240	$ 23,782	$ 167	$ 2,224	$ 201	$ 19
169		Demand	TPLTDEM	$ 80,317	$ 54,908	$ 17,098	$ 1,667	$ 5,736	$ 749	$ 159
170		Commodity	COM	$ 5,877	$ 3,169	$ 1,942	$ 215	$ 471	$ 40	$ 41
171		Total DIMP Deferrals		$ 528,827	$ 474,316	$ 42,822	$ 2,050	$ 8,430	$ 990	$ 219
172		**Cash Working Capital**								
173		Customer	OPEXPCUS	$ (4,184,724)	$ (3,918,269)	$ (238,856)	$ (2,253)	$ (22,781)	$ (2,317)	$ (248)
174		Demand	OPEXPDEM	$ (759,334)	$ (497,668)	$ (176,076)	$ (17,166)	$ (59,070)	$ (7,716)	$ (1,638)

ALLOCATED RATE BASE

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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
175		Commodity	COM	$ (55,566)	$ (29,956)	$ (18,364)	$ (2,035)	$ (4,452)	$ (376)	$ (384)
176		Total Cash Working Capital		$ (4,999,624)	$ (4,445,893)	$ (433,296)	$ (21,454)	$ (86,303)	$ (10,409)	$ (2,270)
177		**Total Rate Base**								
178		Customer		$ 352,248,372	$ 333,749,394	$ 16,375,746	$ 108,093	$ 1,830,835	$ 168,012	$ 16,292
179		Demand		$ 119,831,871	$ 81,395,471	$ 25,864,001	$ 2,521,497	$ 8,676,889	$ 1,133,349	$ 240,664
180		Commodity		$ 1,387,793	$ 748,167	$ 458,643	$ 50,833	$ 111,180	$ 9,386	$ 9,584
181		Total Rate Base		$ 473,468,036	$ 415,893,032	$ 42,698,391	$ 2,680,423	$ 10,618,904	$ 1,310,747	$ 266,540

ALLOCATED COST OF SERVICE

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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1		**Transmission and Distribution Operating Expense**								
2	850-66	**Transmission Expenses**								
3		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	DEM	$ 972,153	$ 718,666	$ 170,572	$ 16,629	$ 57,224	$ 7,474	$ 1,587
5		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6		Total Transmission Expense		$ 972,153	$ 718,666	$ 170,572	$ 16,629	$ 57,224	$ 7,474	$ 1,587
7	870	**Operation Supervision & Engineering**								
8		Customer	871-879CUS	$ 600,373	$ 551,624	$ 42,968	$ 551	$ 4,624	$ 543	$ 63
9		Demand	DEM	$ 114,286	$ 84,486	$ 20,052	$ 1,955	$ 6,727	$ 879	$ 187
10		Commodity	COM	$ 20,346	$ 10,968	$ 6,724	$ 745	$ 1,630	$ 138	$ 141
11		Total Supervision & Engineering		$ 735,005	$ 647,079	$ 69,745	$ 3,251	$ 12,981	$ 1,560	$ 390
12	870	**Odorization**								
13		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15		Commodity	COM	$ 814	$ 439	$ 269	$ 30	$ 65	$ 6	$ 6
16		Total Odorization		$ 814	$ 439	$ 269	$ 30	$ 65	$ 6	$ 6
17	871	**Distribution Load Dispatch**								
18		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Commodity	COM	$ 260,199	$ 140,275	$ 85,992	$ 9,531	$ 20,845	$ 1,760	$ 1,797
21		Total Distribution Load Dispatch		$ 260,199	$ 140,275	$ 85,992	$ 9,531	$ 20,845	$ 1,760	$ 1,797
22	874	**Mains and Services Expenses**								
23		Customer	MSCUS	$ 3,246,664	$ 3,071,955	$ 158,849	$ 731	$ 13,974	$ 1,073	$ 82
24		Demand	DEM	$ 997,962	$ 737,745	$ 175,101	$ 17,071	$ 58,743	$ 7,673	$ 1,629
25		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26		Total Mains & Services		$ 4,244,625	$ 3,809,700	$ 333,949	$ 17,801	$ 72,717	$ 8,746	$ 1,712
27	874	**Odorization**								
28		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Commodity	COM	$ 964	$ 520	$ 319	$ 35	$ 77	$ 7	$ 7
31		Total Odorization		$ 964	$ 520	$ 319	$ 35	$ 77	$ 7	$ 7
32	875	**Meas. & Reg. Station - General**								
33		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Demand	DEM	$ 391,310	$ 289,277	$ 68,659	$ 6,694	$ 23,034	$ 3,009	$ 639
35		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36		Total Meas. & Reg. Station - General		$ 391,310	$ 289,277	$ 68,659	$ 6,694	$ 23,034	$ 3,009	$ 639
37	875	**Odorization**								

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
38		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Commodity	COM	$ 58,361	$ 31,463	$ 19,287	$ 2,138	$ 4,675	$ 395	$ 403
41		Total Odorization		$ 58,361	$ 31,463	$ 19,287	$ 2,138	$ 4,675	$ 395	$ 403
42	876	**Meas. & Reg. Stat. - Industrial**								
43		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Demand	NRDEM	$ 68,073	$ -	$ 45,807	$ 4,466	$ 15,367	$ 2,007	$ 426
45		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Total Meas. & Reg. Stat. - Industrial		$ 68,073	$ -	$ 45,807	$ 4,466	$ 15,367	$ 2,007	$ 426
47	877	**Meas. & Reg. Stat.- City Gate**								
48		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49		Demand	DEM	$ 4,260	$ 3,149	$ 747	$ 73	$ 251	$ 33	$ 7
50		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51		Total Meas. & Reg. Stat. - City Gate		$ 4,260	$ 3,149	$ 747	$ 73	$ 251	$ 33	$ 7
52	878	**Meter & House Reg. Expense**								
53		Customer	MTRGCUS	$ 4,347,173	$ 3,906,496	$ 383,641	$ 6,198	$ 44,358	$ 5,773	$ 707
54		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56		Total Meter & House Reg. Expense		$ 4,347,173	$ 3,906,496	$ 383,641	$ 6,198	$ 44,358	$ 5,773	$ 707
57	879	**Customer Installation Expense**								
58		Customer	METCUS	$ 84,335	$ 76,266	$ 7,034	$ 113	$ 806	$ 103	$ 13
59		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61		Total Customer Install. Expense		$ 84,335	$ 76,266	$ 7,034	$ 113	$ 806	$ 103	$ 13
62	880	**Other Expenses**								
63		Customer	871-879CUS	$ 1,446,075	$ 1,328,656	$ 103,495	$ 1,326	$ 11,138	$ 1,309	$ 151
64		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66		Total Other Expenses		$ 1,446,075	$ 1,328,656	$ 103,495	$ 1,326	$ 11,138	$ 1,309	$ 151
67	880	**Odorization**								
68		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70		Commodity	COM	$ 51	$ 27	$ 17	$ 2	$ 4	$ 0	$ 0
71		Total Odorization		$ 51	$ 27	$ 17	$ 2	$ 4	$ 0	$ 0
72	881	**Rents**								
73		Customer	871-879CUS	$ (153,805)	$ (141,316)	$ (11,008)	$ (141)	$ (1,185)	$ (139)	$ (16)
74		Demand	DEM	$ (29,278)	$ (21,644)	$ (5,137)	$ (501)	$ (1,723)	$ (225)	$ (48)

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
75		Commodity	COM	$ (5,212)	$ (2,810)	$ (1,723)	$ (191)	$ (418)	$ (35)	$ (36)
76		Total Rents		$ (188,295)	$ (165,770)	$ (17,867)	$ (833)	$ (3,326)	$ (400)	$ (100)
77		**Total Distr. & Trans. Op. Expense**								
78		Customer		$ 9,570,816	$ 8,793,681	$ 684,979	$ 8,777	$ 73,717	$ 8,662	$ 999
79		Demand		$ 2,518,766	$ 1,811,679	$ 475,801	$ 46,386	$ 159,622	$ 20,849	$ 4,427
80		Commodity		$ 335,522	$ 180,882	$ 110,885	$ 12,290	$ 26,880	$ 2,269	$ 2,317
81		Total Distr. & Trans. Operations Exp.		$ 12,425,104	$ 10,786,242	$ 1,271,665	$ 67,453	$ 260,218	$ 31,781	$ 7,744
82		**Distribution Maintenance Expenses**								
83	885	**Maintenance Supervision and Engineering**								
84		Customer	887-893CUS	$ 41	$ 38	$ 2	$ 0	$ 0	$ 0	$ 0
85		Demand	887-893DEM	$ 31	$ 17	$ 10	$ 1	$ 3	$ 0	$ 0
86		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87		Total Supervision and Engineering		$ 72	$ 55	$ 12	$ 1	$ 3	$ 0	$ 0
88	886	**Structures and Improvements**								
89		Customer	887-893CUS	$ 204,641	$ 193,839	$ 9,838	$ 43	$ 852	$ 64	$ 5
90		Demand	887-893DEM	$ 157,874	$ 85,717	$ 48,555	$ 4,734	$ 16,289	$ 2,128	$ 452
91		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92		Total Structures and Improvements		$ 362,515	$ 279,556	$ 58,393	$ 4,777	$ 17,141	$ 2,191	$ 457
93	887	**Maintenance of Mains**								
94		Customer	CUS	$ 2,110,004	$ 2,002,005	$ 98,640	$ 397	$ 8,321	$ 593	$ 48
95		Demand	DEM	$ 1,203,699	$ 889,837	$ 211,199	$ 20,590	$ 70,853	$ 9,255	$ 1,965
96		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97		Total Mains		$ 3,313,703	$ 2,891,842	$ 309,839	$ 20,987	$ 79,175	$ 9,847	$ 2,013
98	889	**Maint. of Meas. & Reg. Sta. Equip.- General**								
99		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
100		Demand	DEM	$ 395,845	$ 292,629	$ 69,454	$ 6,771	$ 23,301	$ 3,043	$ 646
101		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102		Total Meas. & Reg. Sta. Equip. - Gen.		$ 395,845	$ 292,629	$ 69,454	$ 6,771	$ 23,301	$ 3,043	$ 646
103	889	**Odorization**								
104		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
105		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
106		Commodity	COM	$ 17,985	$ 9,696	$ 5,944	$ 659	$ 1,441	$ 122	$ 124
107		Total Odorization		$ 17,985	$ 9,696	$ 5,944	$ 659	$ 1,441	$ 122	$ 124
108	890	**Meas. & Reg. Sta. Equip. - Industrial**								
109		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110		Demand	NRDEM	$ 585,505	$ -	$ 393,988	$ 38,410	$ 132,176	$ 17,264	$ 3,666
111		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
112		Total Meas. & Reg. Sta. Eq.- Industrial		$ 585,505	$ -	$ 393,988	$ 38,410	$ 132,176	$ 17,264	$ 3,666
113	891	**Meas. & Reg. Sta. Eq.- City Gate**								
114		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
115		Demand	DEM	$ 19,823	$ 14,654	$ 3,478	$ 339	$ 1,167	$ 152	$ 32
116		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117		Total Meas. & Reg. Sta. Eq.- City Gate		$ 19,823	$ 14,654	$ 3,478	$ 339	$ 1,167	$ 152	$ 32
118	892	**Services**								
119		Customer	SERCUS	$ 740,925	$ 698,779	$ 38,136	$ 199	$ 3,501	$ 288	$ 21
120		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122		Total Services		$ 740,925	$ 698,779	$ 38,136	$ 199	$ 3,501	$ 288	$ 21
123	893	**Meters & House Regulators**								
124		Customer	MTRGCUS	$ 7,092	$ 6,373	$ 626	$ 10	$ 72	$ 9	$ 1
125		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
126		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
127		Total Meters & House Regulators		$ 7,092	$ 6,373	$ 626	$ 10	$ 72	$ 9	$ 1
128	894	**Other Equipment**								
129		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
130		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
131		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
132		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
133		**Total Distr. Maintenance Expense**								
134		Customer		$ 3,062,703	$ 2,901,035	$ 147,242	$ 649	$ 12,747	$ 954	$ 75
135		Demand		$ 2,362,777	$ 1,282,854	$ 726,684	$ 70,845	$ 243,789	$ 31,843	$ 6,762
136		Commodity		$ 17,985	$ 9,696	$ 5,944	$ 659	$ 1,441	$ 122	$ 124
137		Total Distr. Maintenance Expense		$ 5,443,464	$ 4,193,585	$ 879,871	$ 72,153	$ 257,977	$ 32,918	$ 6,961
138		**Total Oper. & Maint. Expense**								
139		Customer		$ 12,633,519	$ 11,694,717	$ 832,222	$ 9,426	$ 86,463	$ 9,616	$ 1,074
140		Demand		$ 4,881,542	$ 3,094,533	$ 1,202,485	$ 117,231	$ 403,411	$ 52,692	$ 11,189
141		Commodity		$ 353,507	$ 190,578	$ 116,828	$ 12,949	$ 28,320	$ 2,391	$ 2,441
142		Total Operations & Maint. Expense		$ 17,868,568	$ 14,979,827	$ 2,151,536	$ 139,606	$ 518,195	$ 64,699	$ 14,705
143		**Customer Accounts Expense**								
144	901	**Supervision**								
145		Customer	902-904CUS	$ 154,499	$ 146,863	$ 7,003	$ 69	$ 508	$ 50	$ 6
146		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
147		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148		Total Supervision		$ 154,499	$ 146,863	$ 7,003	$ 69	$ 508	$ 50	$ 6

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
149	902	**Meter Reading Expense**								
150		Customer	METCUS	$ 1,351,191	$ 1,221,912	$ 112,695	$ 1,807	$ 12,921	$ 1,650	$ 207
151		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
153		Total Meter Reading Expense		$ 1,351,191	$ 1,221,912	$ 112,695	$ 1,807	$ 12,921	$ 1,650	$ 207
154	903	**Customer Accounting**								
155		Customer	903CUS	$ 4,115,966	$ 3,972,244	$ 136,385	$ 254	$ 6,625	$ 427	$ 31
156		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
157		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
158		Total Customer Accounting		$ 4,115,966	$ 3,972,244	$ 136,385	$ 254	$ 6,625	$ 427	$ 31
159	904	**Bad Debt Expense**								
160		Customer	904CUS	$ 677,271	$ 646,588	$ 29,420	$ 673	$ 673	$ (84)	$ -
161		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
162		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
163		Total Bad Debt Expense		$ 677,271	$ 646,588	$ 29,420	$ 673	$ 673	$ (84)	$ -
164	905	**Miscellaneous Customer Accounts**								
165		Customer	902-904CUS	$ 342,471	$ 325,545	$ 15,523	$ 152	$ 1,127	$ 111	$ 13
166		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
167		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
168		Total Misc. Customer Accounts		$ 342,471	$ 325,545	$ 15,523	$ 152	$ 1,127	$ 111	$ 13
169	907-910	**Customer Service Expense**								
170		Customer	CUS	$ 837,188	$ 794,337	$ 39,137	$ 158	$ 3,302	$ 235	$ 19
171		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
172		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173		Total Customer Service Expense		$ 837,188	$ 794,337	$ 39,137	$ 158	$ 3,302	$ 235	$ 19
174		**Sales and Advertising Expense**								
175	912	**Demonstrating and Selling**								
176		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
177		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
178		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179		Total Demon. and Selling Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -
180	913	**Advertising**								
181		Customer	CUS	$ 23,611	$ 22,402	$ 1,104	$ 4	$ 93	$ 7	$ 1
182		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
183		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
184		Total Advertising		$ 23,611	$ 22,402	$ 1,104	$ 4	$ 93	$ 7	$ 1
185		**Administrative & General Exp.**								

ALLOCATED COST OF SERVICE

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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
186	921-32	**Administrative & General Expenses**								
187		Customer	OPEXPCUS	$ 23,122,526	$ 21,650,241	$ 1,319,789	$ 12,446	$ 125,876	$ 12,804	$ 1,370
188		Demand	OPEXPDEM	$ 2,967,828	$ 1,945,118	$ 688,186	$ 67,092	$ 230,873	$ 30,156	$ 6,404
189		Commodity	COM	$ 220,893	$ 119,084	$ 73,001	$ 8,091	$ 17,696	$ 1,494	$ 1,525
190		Total Administrative & General Exp.		$ 26,311,246	$ 23,714,443	$ 2,080,976	$ 87,629	$ 374,446	$ 44,454	$ 9,299
191		**Depreciation & Amortization Expense**								
192	301-03	**Intangible Plant**								
193		Customer	CUS	$ 24,241	$ 23,000	$ 1,133	$ 5	$ 96	$ 7	$ 1
194		Demand	DEM	$ 8,074	$ 5,969	$ 1,417	$ 138	$ 475	$ 62	$ 13
195		Commodity	COM	$ 50	$ 27	$ 16	$ 2	$ 4	$ 0	$ 0
196		Total Intangible Plant		$ 32,365	$ 28,996	$ 2,566	$ 144	$ 575	$ 69	$ 14
197	365	**Land and Land Rights**								
198		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
199		Demand	DEM	$ 32	$ 24	$ 6	$ 1	$ 2	$ 0	$ 0
200		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
201		Total Land and Land Rights		$ 32	$ 24	$ 6	$ 1	$ 2	$ 0	$ 0
202	366	**Meas. and Reg. Station Structures**								
203		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
204		Demand	DEM	$ 95	$ 70	$ 17	$ 2	$ 6	$ 1	$ 0
205		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
206		Total Measuring and Reg. Stat. Struct.		$ 95	$ 70	$ 17	$ 2	$ 6	$ 1	$ 0
207	367	**Transmission Mains**								
208		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
209		Demand	DEM	$ 213,908	$ 158,132	$ 37,532	$ 3,659	$ 12,591	$ 1,645	$ 349
210		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
211		Total Transmission Mains		$ 213,908	$ 158,132	$ 37,532	$ 3,659	$ 12,591	$ 1,645	$ 349
212	368	**Compression Station Equipment**								
213		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
214		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
215		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
216		Total Compression Sta. Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
217	369	**Meas. & Reg. Station Equipment**								
218		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
219		Demand	DEM	$ 50,155	$ 37,077	$ 8,800	$ 858	$ 2,952	$ 386	$ 82
220		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
221		Total Meas. & Reg. Stat. Equipment		$ 50,155	$ 37,077	$ 8,800	$ 858	$ 2,952	$ 386	$ 82
222	371	**Other Equipment**								

ALLOCATED COST OF SERVICE

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LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
223		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
224		Demand	DEM	$ 1,201	$ 888	$ 211	$ 21	$ 71	$ 9	$ 2
225		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
226		Total Other Equipment		$ 1,201	$ 888	$ 211	$ 21	$ 71	$ 9	$ 2
227	375	**Structures and Improvements**								
228		Customer	376-379CUS	$ 690	$ 655	$ 32	$ 0	$ 3	$ 0	$ 0
229		Demand	DEM	$ 445	$ 329	$ 78	$ 8	$ 26	$ 3	$ 1
230		Commodity	COM	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
231		Total Structures and Improvements		$ 1,136	$ 984	$ 111	$ 8	$ 29	$ 4	$ 1
232	376	**Distribution Mains**								
233		Customer	CUS	$ 4,886,752	$ 4,636,628	$ 228,449	$ 920	$ 19,272	$ 1,373	$ 110
234		Demand	DEM	$ 2,787,756	$ 2,060,854	$ 489,135	$ 47,686	$ 164,096	$ 21,434	$ 4,551
235		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
236		Total Distribution Mains		$ 7,674,509	$ 6,697,482	$ 717,584	$ 48,606	$ 183,368	$ 22,807	$ 4,662
237	377	**Compressor Station Equipment**								
238		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
239		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
240		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
241		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
242	378	**Meas. & Reg. Sta. Equip. - General**								
243		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
244		Demand	DEM	$ 296,057	$ 218,861	$ 51,946	$ 5,064	$ 17,427	$ 2,276	$ 483
245		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
246		Total Meas. & Reg. Sta. Eq.- General		$ 296,057	$ 218,861	$ 51,946	$ 5,064	$ 17,427	$ 2,276	$ 483
247	378	**Odorization Tank**								
248		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
249		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
250		Commodity	COM	$ 14,693	$ 7,921	$ 4,856	$ 538	$ 1,177	$ 99	$ 101
251		Total Odorization Tank		$ 14,693	$ 7,921	$ 4,856	$ 538	$ 1,177	$ 99	$ 101
252	379	**Meas.& Reg. Sta. Equip.- City Gate**								
253		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
254		Demand	DEM	$ 40,742	$ 30,119	$ 7,149	$ 697	$ 2,398	$ 313	$ 67
255		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
256		Total Meas. & Reg. Sta. Eq.- City Gate		$ 40,742	$ 30,119	$ 7,149	$ 697	$ 2,398	$ 313	$ 67
257	379	**Odorization Tank**								
258		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
259		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
260		Commodity	COM	$ 4,903	$ 2,643	$ 1,621	$ 180	$ 393	$ 33	$ 34
261		Total Odorization Tank		$ 4,903	$ 2,643	$ 1,621	$ 180	$ 393	$ 33	$ 34
262	380	**Services**								
263		Customer	SERCUS	$ 4,742,152	$ 4,472,410	$ 244,085	$ 1,272	$ 22,409	$ 1,842	$ 136
264		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
265		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
266		Total Services		$ 4,742,152	$ 4,472,410	$ 244,085	$ 1,272	$ 22,409	$ 1,842	$ 136
267	381	**Meters**								
268		Customer	METCUS	$ 2,639,514	$ 2,386,970	$ 220,146	$ 3,529	$ 25,241	$ 3,223	$ 404
269		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
270		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
271		Total Meters		$ 2,639,514	$ 2,386,970	$ 220,146	$ 3,529	$ 25,241	$ 3,223	$ 404
272	382	**Meter Installations**								
273		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
274		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
275		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
276		Total Meter Installations		$ -	$ -	$ -	$ -	$ -	$ -	$ -
277	383	**House Regulators**								
278		Customer	REGCUS	$ 232,452	$ 202,685	$ 25,796	$ 428	$ 3,071	$ 425	$ 48
279		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
280		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
281		Total House Regulators		$ 232,452	$ 202,685	$ 25,796	$ 428	$ 3,071	$ 425	$ 48
282	385	**Meas. & Reg. Sta. Equip. - Industrial**								
283		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
284		Demand	NRDEM	$ 297,860	$ -	$ 200,431	$ 19,540	$ 67,241	$ 8,783	$ 1,865
285		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
286		Total Meas. & Reg. Stat. Eq.- Indus.		$ 297,860	$ -	$ 200,431	$ 19,540	$ 67,241	$ 8,783	$ 1,865
287	385	**Odorization Tank**								
288		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
289		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
290		Commodity	COM	$ 1,029	$ 554	$ 340	$ 38	$ 82	$ 7	$ 7
291		Total Odorization Tank		$ 1,029	$ 554	$ 340	$ 38	$ 82	$ 7	$ 7
292	386	**Other Prop.- Customer Premises**								
293		Customer	CUS	$ (1,701)	$ (1,614)	$ (80)	$ (0)	$ (7)	$ (0)	$ (0)
294		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
295		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
296		Total Other Prop. - Customer Premises		$ (1,701)	$ (1,614)	$ (80)	$ (0)	$ (7)	$ (0)	$ (0)

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
297	387	**Other Equipment**								
298		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
299		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
300		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
301		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -
302	389-98	**General Plant**								
303		Customer	GENPTCUS	$ 4,509,586	$ 4,253,908	$ 231,368	$ 1,408	$ 20,964	$ 1,776	$ 162
304		Demand	DISPLTDEM	$ 595,539	$ 401,192	$ 130,777	$ 12,749	$ 43,873	$ 5,731	$ 1,217
305		Commodity	COM	$ 4,909	$ 2,647	$ 1,622	$ 180	$ 393	$ 33	$ 34
306		Total General Plant		$ 5,110,034	$ 4,657,747	$ 363,767	$ 14,337	$ 65,230	$ 7,540	$ 1,413
307	4073	**Pension & FAS 106 Amort. Expense**								
308		Customer	CUS	$ 276,921	$ 262,747	$ 12,946	$ 52	$ 1,092	$ 78	$ 6
309		Demand	DEM	$ 50,248	$ 37,146	$ 8,816	$ 860	$ 2,958	$ 386	$ 82
310		Commodity	COM	$ 3,677	$ 1,982	$ 1,215	$ 135	$ 295	$ 25	$ 25
311		Total Pension & FAS 106 Amort. Exp.		$ 330,846	$ 301,875	$ 22,977	$ 1,046	$ 4,344	$ 489	$ 114
312		**Total Depreciation & Amort. Exp.**								
313		Customer		$ 17,310,608	$ 16,237,389	$ 963,875	$ 7,613	$ 92,140	$ 8,723	$ 867
314		Demand		$ 4,342,113	$ 2,950,661	$ 936,313	$ 91,282	$ 314,116	$ 41,029	$ 8,712
315		Commodity		$ 29,262	$ 15,775	$ 9,671	$ 1,072	$ 2,344	$ 198	$ 202
316		Total Depreciation & Amort. Expense		$ 21,681,983	$ 19,203,825	$ 1,909,859	$ 99,967	$ 408,600	$ 49,950	$ 9,782
317		**Taxes Other Than Income**								
318	4081	**Payroll and Other Taxes**								
319		Customer	OPEXPCUS	$ 2,196,761	$ 2,056,886	$ 125,387	$ 1,182	$ 11,959	$ 1,216	$ 130
320		Demand	OPEXPDEM	$ 398,610	$ 261,250	$ 92,431	$ 9,011	$ 31,009	$ 4,050	$ 860
321		Commodity	COM	$ 29,169	$ 15,725	$ 9,640	$ 1,068	$ 2,337	$ 197	$ 201
322		Total Payroll and Other Taxes		$ 2,624,541	$ 2,333,861	$ 227,457	$ 11,262	$ 45,304	$ 5,464	$ 1,192
323		**Ad Valorem Taxes**								
324		Customer	CUS	$ 3,284,495	$ 3,116,381	$ 153,546	$ 618	$ 12,953	$ 923	$ 74
325		Demand	DEM	$ 1,093,945	$ 808,701	$ 191,942	$ 18,713	$ 64,393	$ 8,411	$ 1,786
326		Commodity	COM	$ 6,763	$ 3,646	$ 2,235	$ 248	$ 542	$ 46	$ 47
327		Total Ad Valorem Taxes		$ 4,385,203	$ 3,928,728	$ 347,723	$ 19,578	$ 77,888	$ 9,379	$ 1,907
328		**Revenue Related Taxes**								
329		Customer	TOTREVCUS	$ 141,127	$ 104,097	$ 31,342	$ 1,229	$ 4,024	$ 348	$ 87
330		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
331		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
332		Total Revenue Related Taxes		$ 141,127	$ 104,097	$ 31,342	$ 1,229	$ 4,024	$ 348	$ 87
333		**Total Taxes Other Than Income**								

ALLOCATED COST OF SERVICE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
334		Customer		$ 5,622,383	$ 5,277,363	$ 310,275	$ 3,030	$ 28,936	$ 2,487	$ 291
335		Demand		$ 1,492,556	$ 1,069,951	$ 284,372	$ 27,724	$ 95,402	$ 12,461	$ 2,646
336		Commodity		$ 35,932	$ 19,371	$ 11,875	$ 1,316	$ 2,879	$ 243	$ 248
337		Total Taxes Other Than Income		$ 7,150,871	$ 6,366,686	$ 606,522	$ 32,070	$ 127,216	$ 15,191	$ 3,186
338		**Interest on Customer Deposits**								
339		Customer	DEPCUS	$ 150,792	$ 88,981	$ 60,974	$ 678	$ 143	$ 16	$ -
340		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
341		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -
342		Total Interest on Cust. Deposits		$ 150,792	$ 88,981	$ 60,974	$ 678	$ 143	$ 16	$ -
343		**Required Return**								
344		Customer	CUS	$ 27,921,150	$ 26,492,028	$ 1,305,278	$ 5,256	$ 110,114	$ 7,844	$ 631
345		Demand	DEM	$ 9,498,536	$ 7,021,812	$ 1,666,597	$ 162,478	$ 559,112	$ 73,030	$ 15,508
346		Commodity	COM	$ 110,004	$ 59,304	$ 36,355	$ 4,029	$ 8,813	$ 744	$ 760
347		Total Required Return		$ 37,529,690	$ 33,573,144	$ 3,008,229	$ 171,763	$ 678,038	$ 81,618	$ 16,898
348		**Income Taxes**								
349		Customer	CUS	$ 5,844,315	$ 5,545,178	$ 273,214	$ 1,100	$ 23,048	$ 1,642	$ 132
350		Demand	DEM	$ 1,988,186	$ 1,469,770	$ 348,844	$ 34,009	$ 117,031	$ 15,286	$ 3,246
351		Commodity	COM	$ 23,026	$ 12,413	$ 7,610	$ 843	$ 1,845	$ 156	$ 159
352		Total Income Taxes		$ 7,855,526	$ 7,027,361	$ 629,667	$ 35,952	$ 141,924	$ 17,084	$ 3,537
353		**Total Cost of Service Before**								
354		**Revenue Credits**								
355		Customer		$ 100,107,489	$ 94,115,788	$ 5,406,893	$ 42,666	$ 491,970	$ 45,529	$ 4,642
356		Demand		$ 25,170,760	$ 17,551,845	$ 5,126,797	$ 499,815	$ 1,719,945	$ 224,654	$ 47,705
357		Commodity		$ 772,623	$ 416,526	$ 255,340	$ 28,300	$ 61,897	$ 5,225	$ 5,336
358		**Total Cost of Service Before Revenue Credits**		$ 126,050,873	$ 112,084,159	$ 10,789,030	$ 570,781	$ 2,273,812	$ 275,408	$ 57,683

ALLOCATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Customer Cost Allocation Factors**								
2									
3	Total Customers		3,718,286	3,527,969	173,825	700	14,664	1,045	84
4	**Total Customers Factor (CUS)**	**CUS**	**1.00000**	**0.94882**	**0.04675**	**0.00019**	**0.00394**	**0.00028**	**0.00002**
5									
6	Services Weighting			1.00000	1.10767	1.43311	1.20545	1.39076	1.27428
7	Weighted Customers		3,740,750	3,527,969	192,541	1,003	17,677	1,453	107
8	**Weighted Services Customer Factor (SERCUS)**	**SERCUS**	**1.00000**	**0.94312**	**0.05147**	**0.00027**	**0.00473**	**0.00039**	**0.00003**
9									
10	Meters Weighting			1.00000	1.87187	7.45262	2.54411	4.56058	7.11284
11	Weighted Customers		3,901,232	3,527,969	325,379	5,216	37,307	4,764	597
12	**Weighted Meters Customer Factor (METCUS)**	**METCUS**	**1.00000**	**0.90432**	**0.08340**	**0.00134**	**0.00956**	**0.00122**	**0.00015**
13									
14	Regulators Weighting			1.00000	2.58306	10.64409	3.64475	7.08421	9.94514
15	Weighted Customers		4,046,101	3,527,969	449,001	7,450	53,446	7,401	835
16	**Weighted Regulators Customer Factor (REGCUS)**	**REGCUS**	**1.00000**	**0.87194**	**0.11097**	**0.00184**	**0.01321**	**0.00183**	**0.00021**
17									
18	Meters and Regulators Weighting			1.00000	1.99320	7.99706	2.73187	4.99109	7.59601
19	Weighted Customers		3,925,945	3,527,969	346,468	5,597	40,060	5,214	638
20	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS)**	**MTRGCUS**	**1.00000**	**0.89863**	**0.08825**	**0.00143**	**0.01020**	**0.00133**	**0.00016**
21									
22	Non-Residential Customers		190,318	0	173,825	700	14,664	1,045	84
23	**Non-Residential Customers Factor (NRCUS)**	**NRCUS**	**1.00000**	**0.00000**	**0.91334**	**0.00368**	**0.07705**	**0.00549**	**0.00044**
24									
25	**Customer Cost Allocation Factors**								
26									
27	Distribution Plant Customer Costs		$ 481,595,709	$ 452,280,159	$ 26,370,959	$ 195,614	$ 2,495,979	$ 230,794	$ 22,204
28	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	**DISPLTCUS**	**1.00000**	**0.93913**	**0.05476**	**0.00041**	**0.00518**	**0.00048**	**0.00005**
29									
30	Account 376-379 Customer Costs		$ 216,872,700	$ 205,772,242	$ 10,138,517	$ 40,823	$ 855,288	$ 60,931	$ 4,899
31	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	**376-379CUS**	**1.00000**	**0.94882**	**0.04675**	**0.00019**	**0.00394**	**0.00028**	**0.00002**
32									
33	Total Revenue (inc. cost of gas)		$ 175,403,465	$ 129,379,490	$ 38,954,004	$ 1,527,956	$ 5,001,287	$ 432,647	$ 108,082
34	**Total Revenue (TOTREVCUS)**	**TOTREVCUS**	**1.00000**	**0.73761**	**0.22208**	**0.00871**	**0.02851**	**0.00247**	**0.00062**
35									
36	Mains - Customer Cost Factor		**0.53882**	**0.51124**	**0.02519**	**0.00010**	**0.00212**	**0.00015**	**0.00001**
37	Services - Customer Cost Factor		**0.46118**	**0.43495**	**0.02374**	**0.00012**	**0.00218**	**0.00018**	**0.00001**
38	**Mains & Svcs. Customer Factor (MSCUS)**	**MSCUS**	**1.00000**	**0.94619**	**0.04893**	**0.00023**	**0.00430**	**0.00033**	**0.00003**
39									
40	Total Plant Customer		$ 552,654,402	$ 519,701,768	$ 29,692,861	$ 208,990	$ 2,776,215	$ 250,758	$ 23,810

ALLOCATION FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
41	**Total Plant Factor (TPLTCUS)**	**TPLTCUS**	**1.00000**	**0.94037**	**0.05373**	**0.00038**	**0.00502**	**0.00045**	**0.00004**
42									
43	Account 871-879 Customer Costs		$ 7,678,172	$ 7,054,717	$ 549,524	$ 7,041	$ 59,139	$ 6,949	$ 802
44	**Account 871-879 Cust. Costs Factor (871-879CUS)**	**871-879CUS**	**1.00000**	**0.91880**	**0.07157**	**0.00092**	**0.00770**	**0.00091**	**0.00010**
45									
46	Account 887-893 Customer Costs		$ 2,858,021	$ 2,707,158	$ 137,402	$ 606	$ 11,895	$ 890	$ 70
47	**Account 887-893 Cust. Costs Factor (887-893CUS)**	**887-893CUS**	**1.00000**	**0.94721**	**0.04808**	**0.00021**	**0.00416**	**0.00031**	**0.00002**
48									
49	Account 903 Customer		$ 4,115,966	$ 3,972,244	$ 136,385	$ 254	$ 6,625	$ 427	$ 31
50	**Account 903 Customer Factor (903CUS)**	**903CUS**	**1.00000**	**0.96508**	**0.03314**	**0.00006**	**0.00161**	**0.00010**	**0.00001**
51									
52	**Customer Cost Allocation Factors**								
53									
54	Account 904 Customer		$ 677,271	$ 646,588	$ 29,420	$ 673	$ 673	$ (84)	$ -
55	**Account 904 Customer Factor (904CUS)**	**904CUS**	**1.00000**	**0.95470**	**0.04344**	**0.00099**	**0.00099**	**-0.00012**	**0.00000**
56									
57	Accounts 902-904 Customer		$ 6,144,429	$ 5,840,744	$ 278,500	$ 2,734	$ 20,220	$ 1,993	$ 238
58	**Accts. 902-904 Customer Factor (902-904CUS)**	**902-904CUS**	**1.00000**	**0.95058**	**0.04533**	**0.00044**	**0.00329**	**0.00032**	**0.00004**
59									
60	Operating Expense Customer		$ 37,446,324	$ 35,061,997	$ 2,137,364	$ 20,156	$ 203,853	$ 20,736	$ 2,218
61	**Operating Exp. Customer Factor (OPEXPCUS)**	**OPEXPCUS**	**1.00000**	**0.93633**	**0.05708**	**0.00054**	**0.00544**	**0.00055**	**0.00006**
62									
63	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 39,919,126	$ 37,489,181	$ 2,185,870	$ 16,214	$ 206,890	$ 19,130	$ 1,841
64	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 30,237,053	$ 28,689,394	$ 1,413,543	$ 5,692	$ 119,247	$ 8,495	$ 683
65	Total General Plant Customer Costs		$ 70,156,179	$ 66,178,574	$ 3,599,413	$ 21,906	$ 326,137	$ 27,625	$ 2,524
66	**General Plant Customer Factor (GENPTCUS)**	**GENPTCUS**	**1.00000**	**0.94330**	**0.05131**	**0.00031**	**0.00465**	**0.00039**	**0.00004**
67									
68	Customer Deposits		$ (7,853,752)	$ (4,634,440)	$ (3,175,747)	$ (35,306)	$ (7,435)	$ (824)	$ -
69	**Customer Deposits Factor (DEPCUS)**	**DEPCUS**	**1.00000**	**0.59009**	**0.40436**	**0.00450**	**0.00095**	**0.00010**	**0.00000**
70									
71	**Demand Cost Allocation Factors**								
72									
73	System Demand								
74	**System Demand Factor (DEM)**	**DEM**	**1.00000**	**0.73925**	**0.17546**	**0.01711**	**0.05886**	**0.00769**	**0.00163**
75									
76	Non-Residential Demand								
77	**Non-Residential Demand Factor (NRDEM)**	**NRDEM**	**1.00000**	**0.00000**	**0.67290**	**0.06560**	**0.22575**	**0.02949**	**0.00626**
78									
79	Distribution Plant Demand		$ 156,076,970	$ 105,143,204	$ 34,273,527	$ 3,341,347	$ 11,498,128	$ 1,501,850	$ 318,914
80	**Distribution Plant Demand Factor (DISPLTDEM)**	**DISPLTDEM**	**1.00000**	**0.67366**	**0.21959**	**0.02141**	**0.07367**	**0.00962**	**0.00204**

ALLOCATION FACTORS

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CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
81									
82	**Demand Cost Allocation Factors**								
83									
84	Total Plant Demand		$ 184,069,015	$ 125,836,381	$ 39,184,963	$ 3,820,166	$ 13,145,823	$ 1,717,067	$ 364,615
85	**Total Plant Demand Factor (TPLTDEM)**	**TPLTDEM**	**1.00000**	**0.68364**	**0.21288**	**0.02075**	**0.07142**	**0.00933**	**0.00198**
86									
87	Operating Expense Demand		$ 9,223,655	$ 6,045,194	$ 2,138,799	$ 208,513	$ 717,527	$ 93,721	$ 19,901
88	**Operating Expense Demand Factor (OPEXPDEM)**	**OPEXPDEM**	**1.00000**	**0.65540**	**0.23188**	**0.02261**	**0.07779**	**0.01016**	**0.00216**
89									
90	Acct. 887-893 Demand		$ 2,204,871	$ 1,197,120	$ 678,120	$ 66,110	$ 227,497	$ 29,715	$ 6,310
91	**Acct. 887-893 Demand Factor (887-893DEM)**	**887-893DEM**	**1.00000**	**0.54294**	**0.30756**	**0.02998**	**0.10318**	**0.01348**	**0.00286**
92									
93	Rate Base Demand		$ 119,831,871	$ 81,395,471	$ 25,864,001	$ 2,521,497	$ 8,676,889	$ 1,133,349	$ 240,664
94	**Rate Base Demand Factor (RBDEM)**	**RBDEM**	**1.00000**	**0.67925**	**0.21584**	**0.02104**	**0.07241**	**0.00946**	**0.00201**
95									
96	**Commodity Cost Allocation Factors**								
97									
98	Annual Distribution Volumes (Ccf)		195,877,421	105,598,596	64,734,346	7,174,749	15,692,266	1,324,758	1,352,707
99	**Distribution Commodity Factor (COM)**	**COM**	**1.00000**	**0.53911**	**0.33048**	**0.03663**	**0.08011**	**0.00676**	**0.00691**

DEPRECIATION AND RESERVE WP

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: DEPRECIATION AND RESERVE WORKPAPER

Line	Account	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
1		Distribution Plant Reserve					
2	374	Land & Land Rights	$ (9,695)	DIS376-379	$ (5,888)	$ (3,799)	$ (8)
4	375	Structures and Improvements	$ 4,229	DIS376-379	$ 2,569	$ 1,657	$ 3
5	376	Distribution Mains	$ (72,946,895)	MAINS	$ (46,449,022)	$ (26,497,873)	$ -
6	377	Compressor Station Equipment	$ -	DEM	$ -	$ -	$ -
7	378	Meas. & Reg. Station Equip.- General	$ (2,833,020)	DEM	$ -	$ (2,833,020)	$ -
8	378	Odorization Tank	$ 104,970	COM	$ -	$ -	$ 104,970
9	379	Meas. & Reg. Station Equip.- City Gate	$ (735,409)	DEM	$ -	$ (735,409)	$ -
10	379	Odorization Tank	$ 39,916	COM	$ -	$ -	$ 39,916
11	380	Services	$ (37,018,022)	CUS	$ (37,018,022)	$ -	$ -
12	381	Meters	$ (24,888,362)	CUS	$ (24,888,362)	$ -	$ -
13	382	Meter Installations	$ (10,203)	CUS	$ (10,203)	$ -	$ -
14	383	House Regulators	$ (3,976,993)	CUS	$ (3,976,993)	$ -	$ -
15	385	Meas. & Reg. Sta. Equipment - Industrial	$ (4,320,871)	DEM	$ -	$ (4,320,871)	$ -
16	386	Other Property - Customer Premises	$ (1,054,327)	DIS376-379	$ (640,344)	$ (413,126)	$ (857)
17	387	Other Equipment	$ -				
18		Total Distribution Plant Reserve	$ (147,644,682)		$ (112,986,265)	$ (34,802,441)	$ 144,024
19							
20		General Plant - Service Area Direct					
21	389	Land & Land Rights	$ 48,883	DISPLT	$ 36,858	$ 11,945	$ 79
22	390	Structures & Improvements	$ 6,549,310	DISPLT	$ 4,938,277	$ 1,600,412	$ 10,622
23	391	Office Furniture and Equip. - Allocated	$ 2,965,763	DISPLT	$ 2,236,229	$ 724,724	$ 4,810
24	392	Transportation Equipment	$ 14,770,453	DISPLT	$ 11,137,141	$ 3,609,358	$ 23,954
25	393	Stores Equipment	$ 8,809	DISPLT	$ 6,642	$ 2,153	$ 14
26	394	Tools, Shop & Garage	$ 7,864,178	DISPLT	$ 5,929,707	$ 1,921,717	$ 12,754
27	394	Odorization Tank	$ 14,329	COM	$ -	$ -	$ 14,329
28	396	Major Work Equipment	$ 1,959,844	DISPLT	$ 1,477,752	$ 478,914	$ 3,178
29	397	Communication Equipment - Alloc.	$ 18,644,496	DISPLT	$ 14,058,226	$ 4,556,032	$ 30,237
30	398	Miscellaneous General Plant	$ 130,360	DISPLT	$ 98,293	$ 31,855	$ 211
31		General Plant - Shared Svcs. & Distrigas					

DEPRECIATION AND RESERVE WP

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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CLASS COST OF SERVICE STUDY: DEPRECIATION AND RESERVE WORKPAPER

Line	Account	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
32	389	Land & Land Rights	$ 245,380	CUS	$ 245,380	$ -	$ -
33	390	Structures & Improvements	$ 2,096,401	CUS	$ 2,096,401	$ -	$ -
34	391	Office Furniture and Equipment	$ 27,371,345	CUS	$ 27,371,345	$ -	$ -
35	392	Transportation Equipment	$ -	CUS	$ -	$ -	$ -
36	393	Stores Equipment	$ -	CUS	$ -	$ -	$ -
37	394	Tools, Shop & Garage	$ 9,329	CUS	$ 9,329	$ -	$ -
38	396	Major Work Equipment	$ -	CUS	$ -	$ -	$ -
39	397	Communication Equipment	$ 514,598	CUS	$ 514,598	$ -	$ -
40	398	Miscellaneous General Plant	$ -	CUS	$ -	$ -	$ -
41		Total General Plant					
42	389	Land & Land Rights	$ 294,263	GENPLT	$ 282,238	$ 11,945	$ 79
43	390	Structures & Improvements	$ 8,645,712	GENPLT	$ 7,034,679	$ 1,600,412	$ 10,622
44	391	Office Furniture and Equipment	$ 30,337,107	GENPLT	$ 29,607,574	$ 724,724	$ 4,810
45	392	Transportation Equipment	$ 14,770,453	GENPLT	$ 11,137,141	$ 3,609,358	$ 23,954
46	393	Stores Equipment	$ 8,809	GENPLT	$ 6,642	$ 2,153	$ 14
47	394	Tools, Shop & Garage	$ 7,873,507	GENPLT	$ 5,939,036	$ 1,921,717	$ 12,754
48	394	Odorization Tank	$ 14,329	COM	$ -	$ -	$ 14,329
49	396	Major Work Equipment	$ 1,959,844	GENPLT	$ 1,477,752	$ 478,914	$ 3,178
50	397	Communication Equipment	$ 19,159,094	GENPLT	$ 14,572,824	$ 4,556,032	$ 30,237
51	398	Miscellaneous General Plant	$ 130,360	GENPLT	$ 98,293	$ 31,855	$ 211
52		Total General Plant	$ 83,193,478		$ 70,156,179	$ 12,937,109	$ 100,190
53		General Plant Depreciation Expense					
54	389	Land & Land Rights	$ -		$ -	$ -	$ -
55	390	Structures & Improvements	$ 517,646		$ 421,188	$ 95,822	$ 636
56	391	Office Furniture and Equipment	$ 2,780,161		$ 2,713,305	$ 66,415	$ 441
57	392	Transportation Equipment	$ -		$ -	$ -	$ -
58	393	Stores Equipment	$ 588		$ 443	$ 144	$ 1
59	394	Tools, Shop & Garage	$ 524,900		$ 395,936	$ 128,114	$ 850
60	394	Tools, Shop & Garage - Odorization	$ 955		$ -	$ -	$ 955
61	396	Major Work Equipment	$ -		$ -	$ -	$ -
62	397	Communication Equipment	$ 1,277,093		$ 971,385	$ 303,693	$ 2,016

DEPRECIATION AND RESERVE WP

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
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CLASS COST OF SERVICE STUDY: DEPRECIATION AND RESERVE WORKPAPER

Line	Account	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
63	398	Miscellaneous General Plant	$ 8,691		$ 7,329	$ 1,351	$ 10
64		Total General Plant Depreciation Exp.	$ 5,110,034	GENDEP	$ 4,509,586	$ 595,539	$ 4,909
65		General Plant					
66		Depreciation Reserve - Service Area Direct					
67	389	Land & Land Rights	$ 3,573	DISPLT	$ 2,694	$ 873	$ 6
68	390	Structures & Improvements	$ (2,387,387)	DISPLT	$ (1,800,125)	$ (583,390)	$ (3,872)
69	391	Office Furniture and Equipment	$ (2,117,321)	DISPLT	$ (1,596,492)	$ (517,396)	$ (3,434)
70	392	Transportation Equipment	$ (4,895,163)	DISPLT	$ (3,691,026)	$ (1,196,199)	$ (7,939)
71	393	Stores Equipment	$ (8,001)	DISPLT	$ (6,033)	$ (1,955)	$ (13)
72	394	Tools, Shop & Garage	$ (2,732,745)	DISPLT	$ (2,060,530)	$ (667,783)	$ (4,432)
73	394	Odorization Tank	$ 955	COM	$ -	$ -	$ 955
74	395	CNG Equipment	$ 37,480	DISPLT	$ 28,261	$ 9,159	$ 61
75	396	Major Work Equipment	$ (746,098)	DISPLT	$ (562,569)	$ (182,319)	$ (1,210)
76	397	Communication Equipment	$ (7,543,426.96)	DISPLT	$ (5,687,856)	$ (1,843,337)	$ (12,234)
77	398	Miscellaneous General Plant	$ (80,161)	DISPLT	$ (60,443)	$ (19,588)	$ (130)
78			$ (20,468,295)		$ (15,434,118)	$ (5,001,935)	$ (32,241)
79		General Plant					
80		Depreciation Reserve - Shared Svcs. & Distrigas					
81	389	Land & Land Rights	$ -	CUS	$ -	$ -	$ -
82	390	Structures & Improvements	$ (305,458)	CUS	$ (305,458)	$ -	$ -
83	391	Office Furniture and Equipment	$ (8,640,890)	CUS	$ (8,640,890)	$ -	$ -
84	392	Transportation Equipment	$ -	CUS	$ -	$ -	$ -
85	393	Stores Equipment	$ -	CUS	$ -	$ -	$ -
86	394	Tools, Shop & Garage	$ (4,188)	CUS	$ (4,188)	$ -	$ -
87	396	Major Work Equipment	$ -	CUS	$ -	$ -	$ -
88	397	Communication Equipment	$ (304,651)	CUS	$ (304,651)	$ -	$ -
89	398	Miscellaneous General Plant	$ -	CUS	$ -	$ -	$ -
90			$ (9,255,188)		$ (9,255,188)	$ -	$ -
91		General Plant					
92		Total Depreciation Reserve					
93	389	Land & Land Rights	$ 3,573		$ 2,694	$ 873	$ 6
94	390	Structures & Improvements	$ (2,692,845)		$ (2,105,583)	$ (583,390)	$ (3,872)

DEPRECIATION AND RESERVE WP

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
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CLASS COST OF SERVICE STUDY: DEPRECIATION AND RESERVE WORKPAPER

Line	Account	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
95	391	Office Furniture and Equipment	$ (10,758,211)		$ (10,237,382)	$ (517,396)	$ (3,434)
96	392	Transportation Equipment	$ (4,895,163)		$ (3,691,026)	$ (1,196,199)	$ (7,939)
97	393	Stores Equipment	$ (8,001)		$ (6,033)	$ (1,955)	$ (13)
98	394	Tools, Shop & Garage	$ (2,736,933)		$ (2,064,719)	$ (667,783)	$ (4,432)
99	394	Odorization Tank	$ 955		$ -	$ -	$ 955
100	395	CNG Equipment	$ 37,480		$ 28,261	$ 9,159	$ 61
101	396	Major Work Equipment	$ (746,098)		$ (562,569)	$ (182,319)	$ (1,210)
102	397	Communication Equipment	$ (7,848,078.02)		$ (5,992,507)	$ (1,843,337)	$ (12,234)
103	398	Miscellaneous General Plant	$ (80,161)		$ (60,443)	$ (19,588)	$ (130)
104		Total General Plant Depr. Reserve	$ (29,723,482)	GENPLTRES	$ (24,689,306)	$ (5,001,935)	$ (32,241)

ADMINISTRATIVE & GENERAL WP

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ADMINISTRATIVE AND GENERAL EXPENSE WORKPAPER

Line	Account	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
1	920	Salaries	$ 6,710,274	NONAGOPEXP	$ 5,325,664	$ 1,291,111	$ 93,498
2	921	Office Supplies & Expenses	$ 1,543,957	NONAGOPEXP	$ 1,225,375	$ 297,070	$ 21,513
3	922	Transferred Credit	$ (4,102,030)	NONAGOPEXP	$ (3,255,610)	$ (789,264)	$ (57,156)
4	923	Outside Services	$ 260,826	NONAGOPEXP	$ 207,007	$ 50,185	$ 3,634
5	924	Property Insurance	$ 213,845	NONAGOPEXP	$ 169,720	$ 41,146	$ 2,980
6	925	Injuries & Damages	$ 1,254,759	NONAGOPEXP	$ 995,850	$ 241,426	$ 17,483
7	926	Employee Pensions & Benefits	$ 4,548,564	NONAGOPEXP	$ 3,610,005	$ 875,181	$ 63,378
8	926	Distrigas	$ 687,456	CUS	$ 687,456	$ -	$ -
9	928	Regulatory Commission Expenses	$ 201,746	NONAGOPEXP	$ 160,117	$ 38,818	$ 2,811
10	929	Computer Services Expense	$ -	NONAGOPEXP	$ -	$ -	$ -
11	930	Advertising	$ 10,076	NONAGOPEXP	$ 7,997	$ 1,939	$ 140
12	930	Other General	$ 3,166,363	NONAGOPEXP	$ 2,513,010	$ 609,234	$ 44,119
13	930	Distrigas	$ 10,193,171	CUS	$ 10,193,171	$ -	$ -
14	930	Odorization	$ 5,971	COM	$ -	$ -	$ 5,971
15	931	Rent	$ 1,377,972	NONAGOPEXP	$ 1,093,638	$ 265,133	$ 19,200
16	932	A&G Maintenance	$ 238,296	NONAGOPEXP	$ 189,125	$ 45,850	$ 3,320
17		Total Administrative & General Expense	$ 26,311,246	ADMINGEN	23,122,526	2,967,828	220,893

SELECTED DATA WP

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
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CLASS COST OF SERVICE STUDY: SELECTED DATA WORKPAPER

CGSA	As Adjusted Test Year Bills/Meters	As Adjusted Volumes	As Adjusted Margin	Gas Costs at As Adjusted Volumes	As Adjusted Margin Plus Gas Costs	Unadjusted Sales Volumes (Excludes Transport)	As Adjusted Sales Volumes (Excludes Transport)	Service Charges with Changes	Cost of Gas Revenue
Residential	3,527,969	105,598,596	80,613,997	48,765,493	129,379,490	111,614,477	105,598,596	2,334,983	
Commercial	173,825	64,734,346	18,406,825	20,547,179	38,954,004	45,250,821	44,493,619	79,289	
Industrial	700	7,174,749	1,224,869	303,087	1,527,956	836,465	656,316	40	
Public Authority	14,664	15,692,266	2,965,123	2,036,163	5,001,287	4,710,237	4,409,183	707	
Pub. Schools Space Heating	1,045	1,324,758	375,105	57,542	432,647	87,569	124,603	4	
Compressed Nat. Gas	84	1,352,707	107,796	286	108,082	620	620	-	
Special Contract	349	63,735,485	2,872,331			-	-	-	
Irrigation	24	197,695	20,483			-	-	-	
Unmetered Service	-	-	2,655						
Total	3,718,659	259,810,602	106,589,184	71,709,750	175,403,465	162,500,188	155,282,938	2,415,023	$75,042,680
				COG Rate	0.46180				

Customer Portion of Mains

CGSA	63.68%
CTSA	60.47%
GCSA	67.26%

Odorization

Plant	CGSA Account	Original Cost	Reserve	Depr. Rate	Depr. Expense	
						Linked to the Odorization Summary
	378	$ 693,072	$ 104,970	2.12%	$ 14,693	
	379	$ 290,146	$ 39,916	1.69%	$ 4,903	
	385	$ 47,838	$ 2,549	2.15%	$ 1,029	
	394	$ 14,329	$ 5,210	6.67%	$ 955	

Expense	870	814	Linked to the Odorization Summary
	874	964	
	875	58,361	
	880	51	
	889	17,985	
	930	5,971	

Distrigas	Per Book Allocated to TGS	Net Adjustments (with O&M	Adjusted Allocated to TGS	Adjusted Allocated to 46.49%
926	1,862,829	(384,209)	1,478,620	$ 687,456
930	23,485,399	(1,561,347)	21,924,052	$ 10,193,171

SELECTED DATA WP

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: SELECTED DATA WORKPAPER

CTSA	Residential	Commercial	Industrial	Public Authority	Pub. Schools Space Heating	Compressed Nat. Gas	
WEIGHTED RELATIVE COSTS:							
Meters	1.000000	1.871875	7.452621	2.544110	4.560576	7.112841	Linked to Meters & Regulators Factors tab within the model
Regulators	1.000000	2.583060	10.644086	3.644746	7.084215	9.945137	Linked to Meters & Regulators Factors tab within the model
Services	1.000000	1.107673	1.433115	1.205455	1.390762	1.274277	Linked to Service Line Factors tab within the model
Meters & Regulators	1.000000	1.993197	7.997057	2.731869	4.991087	7.596006	Linked to Meters & Regulators Factors tab within the model
PEAK DEMANDS:							
Total System	0.739252	0.175458	0.017106	0.058863	0.007689	0.001633	Linked to Peak Demand tab within the model
Account 385 Factor	-	0.672904	0.065602	0.225747	0.029486	0.006261	Linked to Peak Demand tab within the model - Non Residential
OTHER ACCOUNTS:							
Account 903	0.965082	0.033136	0.000062	0.001610	0.000104	0.000008	Linked to 903 Factors tab within the model
Account 904	0.954696	0.043439	0.000994	0.000994	(0.000124)	-	Linked to 904 Factors tab within the model
Customer Deposits	0.590092	0.404360	0.004495	0.000947	0.000105	-	Linked to Customer Deposits Factors tab within the model

903 FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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CLASS COST OF SERVICE STUDY: 903 FACTORS

Central Gulf Service Area	Pay Agreements		Service Orders		Customers		903
	Number	%	Number	%	Number	%	Factor
Residential	19,442	0.97380	39,917	0.97259	293,997	0.94885	**0.96508**
Commercial	513	0.02569	1,108	0.02700	14,474	0.04672	**0.03314**
Industrial	-	0.00000	-	0.00000	57	0.00019	**0.00006**
Public Authority	10	0.00050	16	0.00039	1,222	0.00394	**0.00161**
Public Schools Speace Heating	0	0.00000	1	0.00003	87	0.00028	**0.00010**
Compressed Natural Gas	-	0.00000	-	0.00000	7	0.00002	**0.00001**

Central Texas Service Area	Pay Agreements		Service Orders		Customers		**903**
	Number	%	Number	%	Number	%	**Factor**
Residential	16,211	0.97194	36,646	0.97166	251,671	0.94824	0.96394
Commercial	460	0.02758	1,056	0.02800	12,633	0.04760	0.03439
Industrial	-	0.00000	-	-	53	0.00020	0.00007
Public Authority	8	0.00048	12	0.00032	958	0.00361	0.00147
Public Schools Speace Heating	0	0.00000	1	0.00003	87	0.00033	0.00012
Compressed Natural Gas	-	0.00000	-	-	7	0.00003	0.00001

Gulf Coast Service Area	Pay Agreements		Service Orders		Customers		903
	Number	%	Number	%	Number	%	Factor
Residential	3,231	0.98326	3,271	0.98317	42,327	0.95252	0.97298
Commercial	53	0.01613	52	0.01563	1,841	0.04144	0.02440
Industrial	-	0.00000	-	0.00000	4	0.00009	0.00003
Public Authority	2	0.00061	4	0.00120	264	0.00595	0.00259

Source: Account 903 CGSA.xlsx

904 FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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CLASS COST OF SERVICE STUDY: 904 FACTORS

CENTRAL GULF SERVICE AREA

Test Year End June 2019

	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
3-yr. avg.	538,903	514,489	23,410	536	536	(67)	-
Factor	**1.0000**	**0.9547**	**0.0434**	**0.0010**	**0.0010**	**(0.0001)**	-

CENTRAL TEXAS SERVICE AREA

	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
3-yr. avg.	435,432	416,061	18,367	536	536	(67)	-
Factor	**1.0000**	**0.9555**	**0.0422**	**0.0012**	**0.0012**	**(0.0002)**	-

GULF COAST SERVICE AREA

	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
3-yr. avg.	103,471.30	98,428	5,043	-	-	-	-
Factor	**1.0000**	**0.9513**	**0.0487**	-	-	-	-

Source: Account 904 CGSA.xlsx

BILL DETERMINANTS SUMMARY CGSA

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

BILLING DETERMINANTS SUMMARY - CENTRAL-GULF SERVICE AREA

Gas Sales	Test Year Bills	Test Year Volumes	As Adjusted Bills	As Adjusted Volumes	January Adjusted Volumes
Residential	3,503,137	111,614,477	3,527,969	105,598,596	23,665,396
Commercial	169,934	45,250,821	169,440	44,493,619	6,228,601
Industrial	282	836,465	256	656,316	111,490
Public Authority	10,222	4,710,237	9,971	4,409,183	832,858
Public Schools Space Heating	57	87,569	65	124,603	12,364
Irrigation	24	197,695	24	197,695	2,198
CNG	36	620	36	620	90
Gas Sales Total	3,683,691	162,697,883	3,707,760	155,480,633	30,852,999
					-
Standard Transportation					
Commercial	4,349	17,966,142	4,385	20,240,726	2,093,803
Industrial	427	6,159,860	444	6,518,433	613,119
Public Authority	4,668	7,555,609	4,681	7,397,100	907,949
Public Schools Space Heating	1,012	1,285,254	980	1,200,155	178,961
CNG	48	1,352,087	48	1,352,087	104,785
COGEN	12	3,885,983	12	3,885,983	339,785
Standard Transportation Total	10,516	38,204,935	10,550	40,594,483	4,238,403
Transport - Special Contract	493	66,760,929	349	63,735,485	4,927,196
Total	3,694,700	267,663,746	3,718,659	259,810,602	40,018,597

Source: SCH G-2 Billing Determinants By Class.xlsx

CUSTOMER DEPOSIT FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: CUSTOMER DEPOSIT FACTORS

Central Gulf Service Area

	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	$ 8,006,997	$ 4,724,869	$ 3,237,713	$ 35,995	$ 7,580	$ 840	$ -
Assignments		**0.5901**	**0.4044**	**0.0045**	**0.0009**	**0.0001**	**-**

Central Texas Service Area

	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	$ 6,764,736	$ 3,908,854	$ 2,813,716	$ 33,995	$ 7,330	$ 840	$ -
Assignments		**0.5778**	**0.4159**	**0.0050**	**0.0011**	**0.0001**	**-**

Gulf Coast Service Area

	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
	$ 1,242,261	$ 816,014	$ 423,997	$ 2,000	$ 250	$ -	$ -
Assignments		**0.6569**	**0.3413**	**0.0016**	**0.0002**	**-**	**-**

Source: Customer Deposits CGSA.xlsx

MAINS STUDY SUMMARY

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: MAINS STUDY SUMMARY

Central-Gulf Coast

Size	Footage	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	223,729	1	0	27.57	3.3167	**5,815,845**
2	6,559,032	2	0	28.24	3.3407	**192,048,378**
3	130,733	3	0	46.74	3.8446	**4,311,581**
4	2,436,065	4	0	37.38	3.6212	**90,494,477**
5	79	5	0	39.86	3.6855	**3,314**
6	1,502,197	6	0	48.54	3.8825	**70,798,216**
7	412	7	0	56.00	4.0253	**21,863**
8	325,882	8	0	73.95	4.3034	**19,485,770**
10	145,807	10	0	102.28	4.6277	**11,061,117**
12	325,882	12	0	101.35	4.6186	**31,364,772**
14	21,548	14	0	133.94	4.8974	**2,631,147**
16	28,222	16	0	154.50	5.0402	**4,372,084**
20	20,508	20	0	211.76	5.3554	**5,113,810**
1	52,335	1	1	13.81	2.6256	**793,969**
2	4,998,323	2	1	15.42	2.7358	**85,410,970**
3	181,278	3	1	18.12	2.8971	**3,489,122**
4	1,691,522	4	1	21.53	3.0693	**36,671,552**
6	960,786	6	1	27.20	3.3032	**26,426,552**
8	66,069	8	1	36.44	3.5956	**2,305,534**
12	380	12	1	70.82	4.2601	**21,353**
1	655	1	0	26.69	3.2843	**17,019**
2	6,706	2	0	24.69	3.2062	**196,340**
3	2,851	3	0	27.97	3.3311	**94,033**
4	131,266	4	0	31.39	3.4465	**4,876,247**
6	5,359	6	0	43.34	3.7692	**252,578**
8	1,859	8	0	58.16	4.0633	**111,131**
16	1,362	16	0	113.33	4.7303	**211,038**
Total	19,820,845					598,399,815

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.978618525
R Square	0.957694218
Adjusted R Square	0.954168736
Standard Error	0.154702102
Observations	27

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	13.00261825	6.501309127	271.6491719	3.28698E-17
Residual	24	0.574385771	0.02393274		
Total	26	13.57700402			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	3.138903744	0.055900794	56.15132669	5.58736E-27	3.023530176	3.254277313
Size	0.119000231	0.005934051	20.05379325	1.68514E-16	0.106752952	0.131247511
Plastic	-0.538532024	0.069245933	-7.777092497	5.18516E-08	-0.681448605	-0.395615443

Zero-Inch Study:

	Zero-Inch Cost/Ft	**Footage**	**Zero-Inch Cost**	**Configured Cost**	**Customer Portion**
Plastic	13.47	7,950,693	107,085,841		
Steel/Wrought Iron	23.08	11,870,153	273,945,950		
			381,031,792	**598,399,815**	**63.68%**

Minimum System Study:

	2-inch System Cost	**Configured Cost**	**Customer Portion**
Cost/Ft	483,418,761	598,399,815	**80.79%**

MAINS STUDY SUMMARY

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: MAINS STUDY SUMMARY

Central Texas

Size	Footage	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	131,736	1	0	22.82	3.1275	**3,044,909.49**
2	4,877,242	2	0	24.85	3.2130	**127,939,591**
3	31,258	3	0	32.69	3.4870	**930,566**
4	1,875,773	4	0	33.68	3.5168	**63,377,116**
5	79	5	0	39.86	3.6855	**3,037**
6	1,337,429	6	0	46.37	3.8365	**58,202,899**
7	412	7	0	56.00	4.0253	**20,341**
8	264,950	8	0	69.39	4.2397	**14,851,144**
10	80,156	10	0	82.07	4.4076	**5,786,970**
12	325,882	12	0	101.35	4.6186	**30,303,883**
14	898	14	0	132.39	4.8858	**107,509**
16	28,222	16	0	154.50	5.0402	**4,353,747**
20	20,508	20	0	211.76	5.3554	**5,248,531**
1	30,202	1	1	12.89	2.5563	**423,049**
2	3,918,082	2	1	14.43	2.6692	**62,286,692**
3	181,136	3	1	18.11	2.8966	**3,268,034**
4	1,348,665	4	1	19.79	2.9852	**27,615,150**
6	911,682	6	1	26.52	3.2777	**24,044,077**
8	47,853	8	1	33.18	3.5020	**1,625,520**
12	380	12	1	70.82	4.2601	**21,424**
1	444	1	0	21.72	3.0782	**10,251**
2	6,125	2	0	23.35	3.1507	**160,665**
3	2,851	3	0	27.97	3.3311	**84,883**
4	131,002	4	0	31.36	3.4454	**4,426,194**
6	5,359	6	0	43.34	3.7692	**233,224**
8	1,859	8	0	58.16	4.0633	**104,177**
16	1,362	16	0	113.33	4.7303	**210,153**
Total	15,561,543					438,683,737

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.988080529
R Square	0.976303131
Adjusted R Square	0.974328392
Standard Error	0.119381687
Observations	27

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	14.09225148	7.046125742	494.3960211	3.13539E-20
Residual	24	0.342047692	0.014251987		
Total	26	14.43429918			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	3.013874672	0.043137947	69.86597384	3.04012E-29	2.924842325	3.102907019
Size	0.126551862	0.004579233	27.63603742	1.04563E-19	0.117100789	0.136002935
Plastic	-0.500832879	0.053436224	-9.372534916	1.7158E-09	-0.611119826	-0.390545933

Zero-Inch Study:

	Zero-Inch Cost/Ft	**Footage**	**Zero-Inch Cost**	**Configured Cost**	**Customer Portion**
Plastic	12.34	6,437,999	79,460,463		
Steel/Wrought Iron	20.37	9,123,544	185,811,558		
			265,272,021	**438,683,737**	**60.47%**

Minimum System Study:

	2-inch System Cost	**Configured Cost**	**Customer Portion**
Cost/Ft	341,674,838	438,683,737	**77.89%**

MAINS STUDY SUMMARY

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: MAINS STUDY SUMMARY

Gulf Coast

Size	Footage	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	91,993	1	0	34.37	3.5372	**3,260,194.94**
2	1,681,791	2	0	38.05	3.6390	**67,361,800**
3	99,475	3	0	51.16	3.9349	**4,503,099**
4	560,292	4	0	49.80	3.9080	**28,665,957**
6	164,768	6	0	66.23	4.1931	**10,767,965**
8	60,931	8	0	93.80	4.5412	**5,086,409**
10	65,652	10	0	126.94	4.8437	**7,000,456**
14	20,650	14	0	134.01	4.8979	**3,592,719**
1	22,134	1	1	15.08	2.7131	**417,642**
2	1,080,240	2	1	19.03	2.9458	**23,036,899**
3	143	3	1	28.00	3.3321	**3,436**
4	342,857	4	1	28.36	3.3449	**9,339,558**
6	49,104	6	1	39.88	3.6860	**1,708,600**
8	18,216	8	1	44.99	3.8064	**809,630**
1	211	1	0	37.13	3.6144	**7,485**
2	581	2	0	38.76	3.6574	**23,263**
4	264	4	0	47.68	3.8645	**13,507**
Total	4,259,302					165,598,619

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.977508426
R Square	0.955522723
Adjusted R Square	0.949168826
Standard Error	0.13256466
Observations	17

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	2	5.285503776	2.642751888	150.3837353	3.44324E-10
Residual	14	0.246027447	0.017573389		
Total	16	5.531531223			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	3.445431132	0.061075966	56.41222457	6.49064E-18	3.314436212	3.576426052
Size	0.122393867	0.009236218	13.2515141	2.59196E-09	0.10258415	0.142203583
Plastic	-0.630305304	0.067910137	-9.281461226	2.33337E-07	-0.775958062	-0.484652546

Zero-Inch Study:

	Zero-Inch Cost/Ft	**Footage**	**Zero-Inch Cost**	**Configured Cost**	**Customer Portion**
Plastic	16.70	1,512,694	25,254,838		
Steel/Wrought Iron	31.36	2,746,608	86,124,851		
			111,379,689	**165,598,619**	**67.26%**

Minimum System Study:

	2-inch System Cost	**Configured Cost**	**Customer Portion**
Cost/Ft	142,270,862	165,598,619	**85.91%**

Source: Mains Study CGSA.xlsx

METER AND REGULATOR FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: METER AND REGULATOR FACTORS

Central Gulf Service Area

	Residential	Commercial	Industrial	Public Authority	Pub. Sch. Spc. Htg.	Compressed Nat. Gas
January Meters						
CTSA		11,669	56	976	91	6
GCSA		1,855	4	268	-	-
CTCSA						
Meters:						
CTSA		86%	93%	78%	100%	100%
STSA		14%	7%	22%	0%	0%
Factors:						
Meters	**1.0000**	**1.8719**	**7.4526**	**2.5441**	**4.5606**	**7.1128**
Regulators	**1.0000**	**2.5831**	**10.6441**	**3.6447**	**7.0842**	**9.9451**
Meters & Regulators	**1.0000**	**1.9932**	**7.9971**	**2.7319**	**4.9911**	**7.5960**

METER AND REGULATOR FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: METER AND REGULATOR FACTORS

Central Texas Service Area

Item	Meter	Meter Cost	Regulator	Regulator Cost	CCf/hr	Monthly Ccf (1)	Selected Monthly Break for Meter Selection	
A	American AC 250	$ 212.03	1813-C 3/4 X 1 AB	$ 43.61	250	651	650	
B	AL 425	$ 433.47	Itron B31-IMRV 1"	$ 137.49	425	1,107	1,100	
C	AC 630	$ 1,047.46	Itron B34-IMR 1-1/2"	$ 531.23	630	1,588	1,590	
D	AL 800	$ 1,664.49	Itron B34-IMR 1-1/2"	$ 531.23	800	2,016	2,020	
E	AL 1000	$ 1,832.16	Itron B34-IMR 1-1/2"	$ 531.23	1000	2,520	2,520	or more

(1) Monthly Ccf is calculated based on assumed load factor of 35%

Distribution of Meter and Regulator Sizes By Class

Item	Residential	Commercial	Industrial	Public Authority	Pub. Sch. Spc. Htg.	Compressed Nat. Gas
A	100%	78%	13%	71%	25%	20%
B	0%	9%	2%	8%	26%	0%
C	0%	4%	4%	5%	11%	0%
D	0%	3%	0%	2%	9%	0%
E	0%	6%	81%	14%	29%	80%
Meter Cost	$ 212.03	$ 402.93	$ 1,562.18	$ 532.97	$ 966.98	$ 1,508.14
Regulator Cost	$ 43.61	$ 114.94	$ 459.40	$ 155.52	$ 308.94	$ 433.71
Meter and Regulator	$ 255.64	$ 517.86	$ 2,021.58	$ 688.49	$ 1,275.92	$ 1,941.84
Weighted Factors						
Meters	**1.0000**	**1.9003**	**7.3677**	**2.5137**	**4.5606**	**7.1128**
Regulators	**1.0000**	**2.6356**	**10.5343**	**3.5661**	**7.0842**	**9.9451**
Meters & Regulators	**1.0000**	**2.0257**	**7.9079**	**2.6932**	**4.9911**	**7.5960**

METER AND REGULATOR FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: METER AND REGULATOR FACTORS

Gulf Coast Service Area

Item	Meter	Meter Cost	Regulator	Regulator Cost	CCf/hr	Monthly Ccf (1)	Selected Monthly Break for Meter Selection	
A	American AC 250	$ 214.19	1813-C 3/4 X 1 AB	$ 44.69	250	651	650	
B	AL 425	$ 435.63	Itron B31-IMRV 1"	$ 138.57	425	1,107	1,100	
C	AC 630	$ 1,049.62	Itron B34-IMR 1-1/2"	$ 533.39	630	1,588	1,590	
D	AL 800	$ 1,670.96	Itron B34-IMR 1-1/2"	$ 533.39	800	2,016	2,020	
E	AL 1000	$ 1,838.64	Itron B34-IMR 1-1/2"	$ 533.39	1000	2,520	2,520	or more

(1) Monthly Ccf is calculated based on assumed load factor of 35%

Distribution of Meter and Regulator Sizes By Class

Item	Residential	Commercial	Industrial	Public Authority	Pub. Sch. Spc. Htg.	Compressed Nat. Gas
A	100%	84%	0%	68%	0%	0%
B	0%	6%	0%	7%	0%	0%
C	0%	3%	0%	8%	0%	0%
D	0%	2%	0%	2%	0%	0%
E	0%	5%	100%	15%	0%	0%
Meter Cost	$ 212.03	$ 358.95	$ 1,832.16	$ 562.94	$ -	$ -
Regulator Cost	$ 43.61	$ 98.24	$ 531.23	$ 171.44	$ -	$ -
Meter and Regulator	$ 255.64	$ 457.20	$ 2,363.39	$ 734.38	$ -	$ -
Weighted Factors						
Meters	**1.0000**	**1.6929**	**8.6411**	**2.6550**	**0.0000**	**0.0000**
Regulators	**1.0000**	**2.2527**	**12.1814**	**3.9312**	**0.0000**	**0.0000**
Meters & Regulators	**1.0000**	**1.7884**	**9.2450**	**2.8727**	**0.0000**	**0.0000**

Source: Meters and Regulators CGSA.xlsx

ODORIZATION SUMMARY

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: ODORIZATION PLANT AND EXPENSE SUMMARY

Odorization Equipment (Plant in Service and CCNC)
Test Year End June 2019

Central Gulf Service Area

Account	Book Cost	Allocated Reserve	Net Value
378	693,072	104,970	588,102
379	290,146	39,916	250,230
385	47,838	2,549	45,289
394	14,329	5,210	9,120
Total	**1,045,385**	**152,644**	**892,741**

Central Texas Service Area

Account	Book Cost	Allocated Reserve	Net Value
378	635,549	92,877	542,673
379	70,153	5,304	64,850
385	47,838	2,549	45,289
394	-	-	-
Total	**753,540**	**100,729**	**652,811**

Gulf Coast Service Area

Account	Book Cost	Allocated Reserve	Net Value
378	57,523	12,093	45,430
379	219,992	34,612	185,380
385	-	-	-
394	14,329	5,210	9,120
Total	**291,844**	**51,915**	**239,930**

Odorization Expense
Test Year End June 2019

Account	**CTSA Net Activity**	**GCSA Net Activity**	**Total Consolidated CGSA Net Activity**
8700	-	814	814
8740	307	657	964
8750	50,467	7,895	58,361
8800	51	-	51
8890	17,985	-	17,985
9302	5,971	0	5,971
Total	**74,780**	**9,365**	**84,146**

PEAK DEMAND

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: PEAK DEMAND SUMMARY

CENTRAL GULF SERVICE AREA PEAK DEMAND

	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	PUB. SCHOOLS SPACE HEATING	COMPRESSED NAT. GAS
Central Texas	2,102,011	1,541,382	379,147	39,480	119,128	18,868	4,007
Gulf Coast	352,068	272,801	51,441	2,499	25,327	-	-
	2,454,079	1,814,183	430,589	41,978	144,454	18,868	4,007
Peak Demand	**1.0000**	**0.7393**	**0.1755**	**0.0171**	**0.0589**	**0.0077**	**0.0016**
Non-Residential Demand	**1.0000**	**0.0000**	**0.6729**	**0.0656**	**0.2257**	**0.0295**	**0.0063**

PEAK DEMAND

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: PEAK DEMAND SUMMARY

CENTRAL TEXAS SERVICE AREA PEAK DEMAND

	TOTAL	RESIDENTIAL	COMM. TRANS.	COMMERCIAL	INDUSTRIAL TRANS.	INDUSTRIAL	PUBLIC AUTH. TRANS.	COGEN TRANS.	PUBLIC AUTHORITY	PUB. SCH. SPC. HTG. TRANS.	PUB. SCHOOLS SPACE HEATING	CNG TRANS.	COMPRESSED NAT. GAS
Austin													
Monthly Base Load		12.13	3,078	275	8,558	1,807	1,231		321	586	568		
Weather Factor		0.1550	5	0.38	17	10.8019	4		2	5	4		
HDD		37	37	37	37	37	37		37	37	37		
Est. Peak Day Use/Customer		6.22	297	24	932	468	188	10,783	84	217	168	1,000	5
Days 28													
Customers - February		240,991	319	11,322	23	17	368	1	395	83	5	4	1
Calculated Peak Day Usage	2,032,538	1,498,780	94,769	273,671	21,445	7,953	69,110	10,783	33,154	18,029	839	4,002	5
Plus Transport		-		94,769		21,445			79,892		18,029		4,002
Est. Peak Usage - Austin	2,032,538	1,498,780		368,440		29,398			113,046		18,868		4,007
South Texas													
Monthly Base Load		9.27	1,588	177		810.68	-	-	130.11	-	-	-	-
Weather Factor		0.1421	6	0.22		2.3366	-	-	1	-	-	-	-
HDD		35	35	35		35			35				
Est. Peak Day Use/Customer		5.31	274	14	1,059	111	-		38	-	-		
Days 28													
Customers - February		8,030	7	627	9	5	160		160				
Calculated Peak Day Usage	69,473	42,602	1,918	8,790	9,528	554	-	-	6,081	-	-	-	-
Plus Transport		-		1,918		9,528			-		-		-
Est. Peak Usage - South Texas	69,473	42,602		10,707		10,082			6,081		-		-
Est. Peak Usage - Central Texas	2,102,011	1,541,382		379,147		39,480			119,128		18,868		4,007
Peak Factors	**1.00000**	**0.73329**		**0.18037**		**0.01878**			**0.05667**		**0.00898**		**0.00191**
Non Residential Demand Factors	**1.00000**			**0.6763**		**0.0704**			**0.2125**		**0.0337**		**0.0071**

NON-WEATHER SENSITIVE CLASSES - CENTRAL TEXAS

	SOUTH TEXAS INDUSTRIAL TRANS.	AUSTIN COGEN. TRANS.	AUSTIN CNG TRANS.	AUSTIN COMPRESSED NAT. GAS
February Per Day Usage	939	10,783	980	3
Assumed Winter Load Factor (1)	88.72%	100.00%	97.95%	64.46%
Calculated Peak Day Usage	1,059	10,783	1,000	5

(1) Average monthly unadjusted usage divided by February average usage. For those classes for which the calculated factor exceeds 100%, 100% is applied.

	SOUTH TEXAS INDUSTRIAL TRANS.	AUSTIN COGEN. TRANS.	AUSTIN CNG TRANS.	AUSTIN COMPRESSED NAT. GAS
February Usage	26,300	301,915	27,438	87
Average Monthly Usage	23,333	323,832	26,874	56

PEAK DEMAND

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: PEAK DEMAND SUMMARY

GULF COAST SERVICE AREA PEAK DEMAND

	TOTAL	RESIDENTIAL	COMM. TRANS.	COMMERCIAL	INDUSTRIAL TRANS.	INDUSTRIAL	PUBLIC AUTHORITY
Galveston							
Monthly Base Load		9.10		321		-	449
Weather Factor		0.1857		0.44		-	3
HDD		33		33			33
Est. Peak Day Use/Customer		6.39	289	26	625	-	128
Days 28							
Customers - February		14,135	26	676	4		65
Calculated Peak Day Usage	126,237	90,333	7,523	17,534	2,499	-	8,349
Plus Transport				7,523		2,499	-
Est. Peak Usage - Galveston	133,760	90,333	7,523	25,057		2,499	8,349
South Jefferson County							
Monthly Base Load		11.64	21,822	232			247
Weather Factor		0.1738	39	0.29			2.28
HDD		36	36	36			36
Est. Peak Day Use/Customer		6.61	2,188	19			90
Days 28							
Customers - February		27,588	3	1,065			188
Calculated Peak Day Usage	225,831	182,468	6,564	19,820			16,978
Plus Transport				6,564			-
Est. Peak Usage - South Jefferson County	225,831	182,468		26,385	-	-	16,978
Est. Peak Usage - Gulf Coast	352,068	272,801		51,441		2,499	25,327
Peak Factors	**1.00000**	**0.77485**		**0.14611**		**0.00710**	**0.07194**
Non Residential Demand Factors	**1.00000**			**0.6490**		**0.0315**	**0.3195**

NON-WEATHER SENSITIVE CLASSES

	GALVESTON COMM. TRANS.	GALVESTON INDUSTRIAL TRANS.
February Per Day Usage	243	565
Assumed Winter Load Factor (1)	84.04%	90.45%
Calculated Peak Day Usage	289	625

(1) Average monthly unadjusted usage divided by February average usage. For those classes for which the calculated factor exceeds 100%, 100% is applied.

	GALVESTON COMM. TRANS.	GALVESTON INDUSTRIAL TRANS.
February Usage	6,808	15,820
Average Monthly Usage	5,722	14,309

Source: Peak Demand CGSA.xlsx

SERVICE CHARGES SUMMARY

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: SERVICE CHARGES SUMMARY

Central Gulf Service Area

	Service Charges	%	Test Year (1)	
Residential	2,067,135	96.69%	2,334,983	
Commercial	70,194	3.28%	79,289	
Industrial	35	0.00%	40	
Public Authority	626	0.03%	707	
Pub. Schools Space Heating	4	0.00%	4	
Compressed Nat. Gas	0	0.00%	-	
	2,137,994		2,415,023	Enter Adjusted Service Charge Amt. from Proof of Rev file

Central Texas Service Area

	Service Charges	%	Test Year (1)	
Residential	1,827,484	96.73%	2,068,317	
Commercial	61,410	3.25%	69,503	
Industrial	35	0.00%	40	
Public Authority	401	0.02%	454	
Pub. Schools Space Heating	4	0.00%	4	
Compressed Nat. Gas	0	0.00%	-	
	1,889,334		2,138,318	Enter Adjusted Service Charge Amt. from Proof of Rev file

Gulf Coast Service Area

	Service Charges	%	Test Year (1)	
Residential	239,651	96.38%	266,680	
Commercial	8,784	3.53%	9,774	
Industrial	0	0.00%	-	
Public Authority	225	0.09%	250	
Pub. Schools Space Heating	0	0.00%	-	
Compressed Nat. Gas	0	0.00%	-	
	248,660		276,705	Enter Adjusted Service Charge Amt. from Proof of Rev file

(1) Test Year includes revenue from proposed service charge changes.

Source: Service Charges CGSA.xlsx

SERVICE LINE FACTORS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: SERVICE LINE FACTORS SUMMARY

Central Gulf (1)	CTSA Factor	CTSA Meters	GCSA Factor	GCSA Meters	Weighted Factor
Residential	1.00000	251,671	1.00000	42,327	**1.00000**
Commercial	1.10091	12,633	1.15405	1,841	**1.10767**
Industrial	1.41042	53	1.73561	4	**1.43311**
Public Authority	1.22230	957	1.14452	264	**1.20545**
Public Schools Space Heating	1.39076	87	-	-	**1.39076**
Compressed Natural Gas	1.27428	7	-	-	**1.27428**

Central Texas		Cost	Factor	Meters	Transportation Factor	Transportation Meters	Weighted Factor
Residential	$	1,230.10	1.00000	251,671	-	-	**1.00000**
Commercial	$	1,344.19	1.09275	12,308	1.41042	325	**1.10091**
Industrial	$	1,734.96	1.41042	21	1.41042	32	**1.41042**
Public Authority	$	1,344.19	1.09275	566	1.41042	390	**1.22230**
Public Schools Space Heating	$	1,344.19	1.09275	5	1.41042	82	**1.39076**
Compressed Natural Gas	$	1,344.19	1.09275	3	1.41042	4	**1.27428**
Transportation	$	1,734.96	1.41042				

Gulf Coast		Cost	Factor	Meters	Transportation Factor	Transportation Meters	Weighted Factor
Residential	$	1,628.79	1.00000	42,327	-	-	**1.00000**
Commercial	$	1,864.18	1.14452	1,812	1.73561	30	**1.15405**
Industrial	$	2,826.94	1.73561	-	1.73561	4	**1.73561**
Public Authority	$	1,864.18	1.14452	264	1.73561	-	**1.14452**
Transportation	$	2,826.94	1.73561				

(1) Cost based on percentage of meters in Central Texas and Gulf Coast.
The cost for Public Schools Space Heating and Compressed Natural Gas uses the 2-inch service lines cost, consistent with the size applicable in Central Texas.

Source: Serevice Lines CGSA.xlsx

SUMMARY AS ADJ REV_CGSA

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

SUMMARY AS ADJUSTED REVENUES - CENTRAL-GULF SERVICE AREA

Line No.	Revenue Class	Central-Gulf Service Area Cost of Service	Adj. to Remove WNA Dollars	Weather Adj.	Switching Adj.	Growth (Loss) Adj.	Post Growth Adj.	GRIP Annualization	COSA Annulization	Unmetered Service Adjustment	Total As Adjusted Revenue
1	Gas Sales										
2	Residential	$ 76,233,987	$ 283,790	$ (638,842)	$ -	$ 435,116	$ 109,581	$ 4,083,621	$ 106,743	-	$ 80,613,997
3	Commercial	13,772,585	80,382	(87,774)	21,598	(36,004)	(8,980)	890,279	26,348	-	14,658,433
4	Industrial	158,954	-	(4,340)	(7,462)	(12,382)	(2,868)	17,865	-	-	149,767
5	Public Authority	1,387,090	11,726	(14,100)	(9,448)	(21,549)	(6,423)	86,378	5,225	-	1,438,899
6	Public School Space Heating	15,440	318	(437)	-	3,895	1,281	687	-	-	21,185
7	CNG	5,501	-	-	-	-	-	1,476	-	-	6,976
8	Irrigation	20,483	-	-	-	-	-	-	-	-	20,483
9	Unmetered Service	-	-	-	-	-	-	-	-	2,655	2,655
9	Total Gas Sales Revenue	$ 91,594,041	$ 376,216	$ (745,492)	$ 4,688	$ 369,076	$ 92,591	$ 5,080,306	$ 138,315	$ 2,655	$ 96,912,395

Line No.		Central-Gulf Service Area Cost of Service	Adjustment to Remove Interest on Storage	Adjustment to Remove Insurance Reimbusement for Hurricane Harvey Related to Loss of Revenues	Service Fee Adj.	Adjustment to Remove Estimated Delivery Charges	Weather Adj.	Switching Adj.	New Customer Adj.	Termination Adj.	GRIP Annualization	COSA Annualization	Special Contract Transportation Switching Adj.	Total As Adjusted Revenue
10	Standard Tranportation													
11	Commercial	$ 3,447,716	$ -	$ -	$ -	$ -	$ (33,289)	$ (26,989)	$ -	$ (9,559)	$ 24,073	$ 394	$ 346,047	$ 3,748,392
12	Industrial	1,002,840	-	-	-	-	(7,378)	10,271	-	-	26,377	1,047	41,944	1,075,101
13	Public Authority	1,299,258	-	-	-	-	(30,392)	10,069	4,062	(1,122)	62,049	-	-	1,343,924
14	Public School Space Heating	352,828	-	-	-	-	(8,059)	-	-	(3,661)	12,813	-	-	353,921
15	CNG	98,737	-	-	-	-	-	-	-	-	2,083	-	-	100,820
16	Cogeneration	182,155	-	-	-	-	-	-	-	-	145	-	-	182,300
17	Total Standard Tranportation Revenue	$ 6,383,534	$ -	$ -	$ -	$ -	$ (79,118)	$ (6,650)	$ 4,062	$ (14,342)	$ 127,541	$ 1,441	$ 387,991	$ 6,804,458
18	Estimated Delivery	$ (1,652)	$ -	$ -	$ -	$ 1,652	$ -	$ -	$ -	$ -	$ -	$ -	$0	$ -
19	Special Contract Tranportation Revenue	2,937,032	-	-	-	-	-	-	-	-	-	-	(64,702)	2,872,331
20	Total Transportation Revenue	$ 9,318,914	$ -		$ -	$ 1,652	$ (79,118)	$ (6,650)	$ 4,062	$ (14,342)	$ 127,541	$ 1,441	$ 323,289	$ 9,676,789
21	Service Fee's - Acct 4880xxx	$ 2,137,994	$ -	$ -	$ 277,029	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,415,023
22	Utility Revenue - Acct 4950	409,496	(347,618)	(61,878)	-	-	-	-	-	-	-	-	-	-
23	Total Transport, Service Fees, & Other Misc Revenue	$ 11,866,404	$ (347,618)	$ (61,878)	$ 277,029	$ 1,652	$ (79,118)	$ (6,650)	$ 4,062	$ (14,342)	$ 127,541	$ 1,441	$ 323,289	$ 12,091,812
24	Total Gas Sales, Transport, and Other Revenue	$ 103,460,444												$ 109,004,207

Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx

SELECTED DATA WP 2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: SELECTED DATA WORKPAPER 2 - RATEBASE SUMMARY

	PLANT	RESERVE
INTANGIBLE PLANT		
(301) Organization	$ 57,564	$ (44,926)
(302) Franchises & Consents	$ 393,474	$ (394,901)
(303) Misc. Intangible	$ 753,928	$ (738,293)
Total Intangible Plant	$ 1,204,966	$ (1,178,119)
TRANSMISSION PLANT		
(332) Field Lines	$ -	$ -
(334) Field Meas/Reg Station Equipment	$ -	$ -
(365) Land & Land Rights	$ 92,083	$ (2,132)
(366) Meas/Reg Station Structures	$ 2,346	$ (2,346)
(367) Mains	$ 12,223,339	$ (3,112,545)
(368) Compressor Station Equip	$ -	$ -
(369) Measure/Reg. Station Equipment	$ 2,390,734	$ (508,102)
(371) Other Equipment	$ 45,840	$ (11,357)
Total Transmission Plant	$ 14,754,342	$ (3,636,481)
DISTRIBUTION PLANT		
(374) Land & Land Rights	$ 5,837,437	$ (9,695)
(375) Structures & Improvements	$ 60,083	$ 4,229
(376) Mains	$ 340,592,534	$ (72,946,895)
(377) Compressor Station Equipment	$ -	$ -
(378) Meas. & Reg. Station - General	$ 14,490,638	$ (2,728,050)
(379) Meas. & Reg. Station - C.G.	$ 2,691,036	$ (695,494)
(380) Services	$ 185,624,492	$ (37,018,022)
(381) Meters	$ 65,333,909	$ (24,888,362)
(382) Meter Installations	$ 6,007	$ (10,203)
(383) House Regulators	$ 9,113,503	$ (3,976,993)
(385) Indust. Meas. & Reg. Stat. Equipment	$ 13,895,639	$ (4,320,871)
(386) Other Property on Customer Premises	$ 1,063,249	$ (1,054,327)
(387) Meas. & Reg. Stat. Equipment	$ 0	$ -
Total Distribution Plant	$ 638,708,527	$ (147,644,682)

SELECTED DATA WP 2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: SELECTED DATA WORKPAPER 2 - RATEBASE SUMMARY

		Direct	Shared Svc.	Distrigas Plt.	Distr. CCNC		Direct	Shared Svc.	Distrigas
GENERAL PLANT			46.49310%	11.72104%	11.62792%			46.49310%	11.69262%
(389) Land & Land Rights	$ 294,263	$ 48,883	$ 245,380	$ -	$ -	$ 3,573	$ 3,573	$ -	$ -
(390) Structures & Improvements	$ 8,645,712	$ 6,549,310	$ 1,436,006	$ 619,865	$ 40,530	$ (2,692,845)	$ (2,387,387)	$ (55,818)	$ (249,640)
(391) Office Furniture & Equipment etc.	$ 30,337,107	$ 2,965,763	$ 1,460,979	$ 22,010,506	$ 3,899,860	$ (10,758,211)	$ (2,117,321)	$ (1,015,116)	$ (7,625,774)
	$ -								
(392) Transportation Equipment	$ 14,770,453	$ 14,770,453	$ -	$ -	$ -	$ (4,895,163)	$ (4,895,163)	$ -	$ -
(393) Stores Equipment	$ 8,809	$ 8,809	$ -	$ -		$ (8,001)	$ (8,001)	$ -	$ -
(394) Tools, Shop & Garage	$ 7,887,837	$ 7,878,507	$ 9,329	$ -	$ -	$ (2,735,978)	$ (2,731,790)	$ (4,188)	$ 0
(395) CNG Equipment	$ 0	$ 0	$ -	$ -	$ -	$ 37,480	$ 37,480	$ -	$ -
(396) Major Work Equipment	$ 1,959,844	$ 1,959,844	$ -	$ -	$ -	$ (746,098)	$ (746,098)	$ -	$ -
(397) Communication Equipment	$ 19,159,094	$ 18,644,496	$ 502,585	$ 12,013	$ -	$ (7,848,078)	$ (7,543,427)	$ (303,404)	$ (1,247)
(398) Miscellaneous General Plant	$ 130,360	$ 130,360	$ -	$ -	$ -	$ (80,161)	$ (80,161)	$ -	$ -
Total General Plant	$ 83,193,478	$ 52,956,425	$ 3,654,280	$ 22,642,384	$ 3,940,390	$ (29,723,482)	$ (20,468,295)	$ (1,378,527)	$ (7,876,661)
Total Orig Cost Plant in Service	$ 737,861,313				Total Reserve	$ (182,182,765)			

GENERAL PLANT DEPRECIATION EXPENSE

GENERAL PLANT		Direct	Shared Svc.	Distrigas
(389) Land & Land Rights	$ -	$ -	$ -	$ -
(390) Structures & Improvements	$ 517,646	$ 399,126	$ 35,909	$ 82,611
(391) Office Furniture & Equipment, etc.	$ 2,780,161	$ 335,358	$ 193,190	$ 2,251,613
(392) Transportation Equipment	$ -	$ -	$ -	$ -
(393) Stores Equipment	$ 588	$ 588	$ -	$ -
(394) Tools, Shop & Garage	$ 524,900	$ 524,279	$ 622	$ -
(394) Odorization	$ 955	$ 955	$ -	$ -
(395) CNG Equipment	$ -	$ -	$ -	$ -
(396) Major Work Equipment	$ -	$ -	$ -	$ -
(397) Communication Equipment	$ 1,277,093	$ 1,242,991	$ 33,506	$ 596
(398) Miscellaneous General Plant	$ 8,691	$ 8,691	$ -	$ -
Total General Plant	$ 5,110,034	$ 2,511,988	$ 263,227	$ 2,334,819

SELECTED DATA WP 3

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS COST OF SERVICE STUDY: SELECTED DATA WORKPAPER 3 - EXPENSE SUMMARY

	Operating Expenses				
850-66	Transmission Expenses	$	972,153		
870	Operation Supervision & Engineering	$	735,005		
870	Odorization	$	814		
871	Distribution Load Dispatch	$	260,199		
874	Mains and Services Expenses	$	4,244,625		
874	Odorization	$	964		
875	Measuring & Reg. Stat. Exp.- General	$	391,310		
875	Odorization	$	58,361		
876	Meas. & Reg. Stat. Exp..- Industrial	$	68,073		
877	Meas. & Regulating Station Exp.- City Gate	$	4,260		
878	Meter and House Regulator Expenses	$	4,347,173		
879	Customer Installation Expenses	$	84,335		
880	Other Expenses	$	1,446,075		
880	Odorization	$	51		
881	Rents	$	(188,295)		
885	Maintenance Supervision and Engineering	$	72		
886	Structures and Improvements	$	362,515		
887	Maintenance of Mains	$	3,313,703		
889	Maint. of Meas. & Reg. Sta. Equip.- General	$	395,845		
889	Odorization	$	17,985		
890	Maint. of Meas. & Reg. Sta. Equip. - Industrial	$	585,505		
891	Maint. of Meas. & Reg. Sta. Equip. - City Gate	$	19,823		
892	Maintenance of Services	$	740,925		
893	Main. of Meters & House Regulators	$	7,092		
894	Maintenance of Other Equipment	$	-		
901	Supervision	$	154,499		
902	Meter Reading Expenses	$	1,351,191		
903	Customer Accounting	$	4,115,966	Gross Up	
904	Bad Debts (includes gross up)	$	677,271	$	91,592
905	Miscellaneous Customer Accounts Expenses	$	342,471		
907	Supervision	$	-		
908	Customer Assistance	$	743,891		
909	Informational and Instructional Advertising	$	93,297		
912	Demonstrating and Selling	$	-		
913	Advertising	$	23,611		

	Depreciation and Amortization Expense				
301-303	Intangible Plant	$	32,365		
365	Land and Land Rights	$	32		
366	Meas. and Reg. Station Structures	$	95		
367	Transmission Mains	$	213,908		
368	Compression Station Equipment	$	-		
369	Measuring and Reg. Station Equipment	$	50,155		
371	Other Equipment	$	1,201		
375	Structures and Improvements	$	1,136		
376	Mains	$	7,674,509		
377	Compressor Station Equipment	$	-		
378	Meas. & Reg. Sta. Equipment - General	$	296,057		
378	Odorization Tank	$	14,693		
379	Meas. & Reg. Sta. Equipment - City Gate	$	40,742		
379	Odorization Tank	$	4,903		
380	Services	$	4,742,152		
381	Meters	$	2,639,514		
382	Meter Installations	$	-		
383	House Regulators	$	232,452		
385	Meas. & Reg. Sta. Equip. - Industrial	$	297,860		
385	Odorization Tank	$	1,029		
386	Other Property - Customer Premises	$	(1,701)		
387	Other Equipment	$	0		
389-	General Plant	$	5,110,034		
4073	Pension & FAS 106 Amortization Expense	$	330,846		
	Taxes Other Than Income				
408	Payroll and Other	$	2,624,541		
408	Ad Valorem	$	4,385,203	Gross Up	
408	Revenue Related (includes gross up)	$	141,127	$	127,850
431	Interest on Customer Deposits	$	150,792		
	Return and Income Taxes				
	Required Return	$	37,529,690		
	Income Taxes	$	7,855,526		
	Other Rate Base				
	Customer Deposits	$	(7,853,752)		
	Customer Advances	$	(21,363,984)		
	Accumulated Deferred Income Taxes	$	(80,421,556)		
	Materials and Supplies	$	4,272,141		
	Prepayments	$	2,581,813		
	Pension & FAS 106 Regulatory Asset	$	25,045,624		
	DIMP Deferrals	$	528,827		
	Cash Working Capital	$	(4,999,624)		

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CLASS REVENUE ALLOCATION

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Current Revenue-to-Cost Ratio (1)	0.8648	0.7630	1.7364	2.1690	1.3335	1.8917
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
5	Rate Design Revenue Increase	$ 17,046,666	$ 26,560,535	$ (7,944,915)	$ (667,238)	$ (850,278)	$ (51,438)
6	% Increase - Non-Gas Revenue (2)	15.64%	31.06%	-42.41%	-53.90%	-25.01%	-47.14%
7	% Increase - Total Revenue (3)	9.43%	19.78%	-20.23%	-43.30%	-15.48%	-47.02%
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)						
9	Revenue-to-Cost Ratio	1.0000	0.9321	1.5891	1.9352	1.2668	1.7134
10	Rate Design Revenue Increase	$ 17,046,666	$ 18,949,440	$ (1,588,983)	$ (133,448)	$ (170,056)	$ (10,288)
11	% Increase - Non-Gas Revenue (2)	15.64%	22.16%	-8.48%	-10.78%	-5.00%	-9.43%
12	% Increase - Total Revenue (3)	9.43%	14.11%	-4.05%	-8.66%	-3.10%	-9.40%
13	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)						
14	Revenue-to-Cost Ratio	1.0000	0.9151	1.7364	2.1690	1.3335	1.8917
15	Rate Design Revenue Increase	$ 17,046,666	$ 17,046,666	$ -	$ -	$ -	$ -
16	% Increase - Non-Gas Revenue (2)	15.64%	19.93%	0.00%	0.00%	0.00%	0.00%
17	% Increase - Total Revenue (3)	9.43%	12.69%	0.00%	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.

CURRENT AND REC. RATES WP

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CURRENT AND RECOMMENDED RATEST WORKPAPER

		Current Rates						
Description		CTSA Incorporated and Environs Rates (1)	CTSA Environs Rates (1)	GCSA Incorporated Rates	GCSA Environs Rates	City of Beaumont Rates	Recommended (1)	
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)
Residential							Rate Option A	Rate Option B
Customer Charge		$18.81	$18.81	$12.42	$14.17	$12.10	$14.00	$27.58
Usage Rates	All Ccf	$0.12061	$0.12061	$0.45616	$0.40680	$0.45616	$0.55702	$0.10435
Commercial								
Customer Charge - Sales		$53.33	$53.33	$51.11	$59.92	$49.49	$53.33	
Usage Rates	All Ccf	$0.11614	$0.11614				$0.12678	
	First 250			$0.22140	$0.20185	$0.22140		
	All Over 250			$0.19380	$0.17425	$0.19380		
Customer Charge - Transportation		$265.33	$265.33	$297.11	$305.92		$265.33	
Usage Rates	All Ccf	$0.11614	$0.11614				$0.12678	
	First 250			0.22140	0.20185			
	All Over 250			0.19380	0.17425			
Industrial								
Customer Charge - Sales		$320.96	$320.96	$153.41	242.79		$320.96	
Usage Rates	All Ccf	$0.10273	$0.10273				$0.12703	
	First 250			$0.40060	$0.37808			
	All Over 250			$0.37480	$0.35228			
Customer Charge - Transportation		$520.96	$520.96	$249.73	$432.79		$520.96	
Usage Rates	All Ccf	$0.10273	$0.10273				$0.12703	
	First 250			0.40060	$0.37808			
	All Over 250			0.37480	$0.35228			
Public Authority								
Customer Charge - Sales		$81.70	$81.70	$106.10	117.78		$81.70	
Usage Rates	All Ccf	$0.11541	$0.11541				$0.12551	
	First 250			$0.15672	0.13587			
	All Over 250			$0.13092	0.11007			
Customer Charge - Transportation		$104.70	$104.70	$302.36	307.78		$104.70	
Usage Rates	All Ccf	$0.11541	$0.11541				$0.12551	
	First 250			$0.15672	0.13587			
	All Over 250			$0.13092	0.11007			

			Transp. Gas Cost Savings Assumed
Gas Costs	CGSA	0.4618	
	CTSA	0.4566	0.05
	GCSA	0.49722	

		CTSA Inc.	CTSA Env.	GCSA Inc.	GCSA Env.	City of Beaumont	Recommended
	Residential						
Annual A	17.99	$ 29.20	$ 29.20	$ 29.57	$ 30.44	$ 29.25	$ 32.33
January A	48.39	$ 46.74	$ 46.74	$ 58.55	$ 57.91	$ 58.23	$ 63.30
Annual B	44.88	$ 44.71	$ 44.71	$ 55.21	$ 54.74	$ 54.89	$ 52.99
January B	120.69	$ 88.47	$ 88.47	$ 127.48	$ 123.27	$ 127.16	$ 95.91
	Commercial Sales	CTSA Inc.	CTSA Env.	GCSA Inc.	GCSA Env.		Recommended
Annual	262.59	$ 203.72	$ 203.72	$ 239.47	$ 243.14	$ 237.85	$ 207.89
January	441.12	$ 305.97	$ 305.97	$ 362.83	$ 363.02	$ 361.21	$ 312.96
	Commercial Transport	CTSA Inc.	CTSA Env.	GCSA Inc.	GCSA Env.		Recommended
Annual	4,615.76	$ 2,803.50	$ 2,803.50	$ 3,378.83	$ 3,297.40		$ 2,875.50
January	5,729.73	$ 3,416.06	$ 3,416.06	$ 4,120.91	$ 4,017.71		$ 3,505.44
	Industrial Sales	CTSA Inc. and Env.					Recommended
Annual	2,564.64	$ 1,755.39					$ 1,831.10
January	5,227.95	$ 3,245.01					$ 3,399.34
	Industrial Transport	CTSA Inc. and Env.		GCSA Inc.	GCSA Env.		Recommended
Annual	14,681.15	$ 8,397.14		$ 12,693.43	$ 12,545.87		$ 8,826.68
January	16,570.79	$ 9,410.89		$ 14,294.25	$ 14,104.13		$ 9,895.73
	Public Authority Sales	CTSA Inc. and Env.		GCSA Inc.	GCSA Env.		Recommended
Annual	442.20	$ 334.64		$ 390.32	$ 392.78		$ 341.41
January	1,002.34	$ 655.03		$ 742.16	$ 732.94		$ 670.39
	Public Authority Transport	CTSA Inc. and Env.					Recommended
Annual	1,580.24	$ 972.51					$ 996.30
January	2,327.58	$ 1,382.92					$ 1,417.97

CURRENT AND REC. RATES WP

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CURRENT AND RECOMMENDED RATEST WORKPAPER

		Current Rates						
Description		CTSA Incorporated and Environs Rates (1)	CTSA Environs Rates (1)	GCSA Incorporated Rates	GCSA Environs Rates	City of Beaumont Rates	Recommended (1)	
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)
Cogeneration								
Customer Charge - Sales		$104.70	$104.70				$104.70	
Usage Rates	First 5,000 Ccf	$0.07720	$0.07720				$0.07720	
	Next 35,000	$0.06850	$0.06850				$0.06850	
	Next 60,000	$0.05524	$0.05524				$0.05524	
	All Over 100,000	$0.04016	$0.04016				$0.04016	
Customer Charge - Transportation		$104.70	$104.70	NA	NA		$104.70	
Usage Rates	First 5,000 Ccf	$0.07720	$0.07720				$0.07720	
	Next 35,000	$0.06850	$0.06850				$0.06850	
	Next 60,000	$0.05524	$0.05524				$0.05524	
	All Over 100,000	$0.04016	$0.04016				$0.04016	
Public Schools Space Heating								
Customer Charge - Sales		$134.70	$134.70	NA	NA		$134.70	
Usage Rates	All Ccf	$0.10012	$0.10012				$0.10012	
Customer Charge - Transportation		$234.70	$234.70	NA	NA		$234.70	
Usage Rates	All Ccf	$0.10012	$0.10012				$0.10012	
Compressed Natural Gas								
Customer Charge - Sales		$192.63	$192.63	NA	NA		$192.63	
Usage Rates	All Ccf	$0.06684	$0.06684				$0.06684	
Customer Charge - Transportation		$217.63	$217.63	NA	NA		$217.63	
Usage Rates	All Ccf	$0.06684	$0.06684				$0.06684	

			Transp. Gas Cost Savings Assumed
Gas Costs	CGSA	0.4618	
	CTSA	0.4566	0.05
	GCSA	0.49722	

	COGEN Transport	CTSA Inc. and Env.	Recommended

	COGEN Transport	CTSA Inc. and Env.	Recommended
Jan	323,831.92	$ 155,654.46	$ 157,260.17
Aug	339,785.00	$ 163,214.82	$ 164,899.63

	Pub. Sch. Spc. Htg. Sales	CTSA Inc. and Env.	Recommended
Annual	1,927.12	$ 1,207.53	$ 1,217.59
January	2,294.74	$ 1,412.18	$ 1,424.16

	Pub. Sch. Spc. Htg. Transport	CTSA Inc. and Env.	Recommended
Annual	1,224.65	$ 888.51	$ 894.58
January	2,191.36	$ 1,404.61	$ 1,415.47

	Compressed Nat. Gas Sales	CTSA Inc. and Env.	Recommended
Annual	17.22	$ 201.64	$ 201.73
January	30.02	$ 208.34	$ 208.50

	CNG Transport	CTSA Inc. and Env.	Recommended
Annual	28,168.48	$ 14,318.55	$ 14,458.22
January	26,196.25	$ 13,331.27	$ 13,461.16

Note 1: The volumetric and customer charge rates are the same in all CTSA incorporated and environs customer classes. Bills under current and recommended rates do not include the Conservation Adjustment Clause rate in the CTSA.

CURRENT AND RECOMMENDED RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CURRENT AND RECOMMENDED RATES

Description		Current Rates: CTSA Incorporated and Environs Rates	Current Rates: GCSA Incorporated Rates	Current Rates: GCSA Environs Rates	City of Beaumont Rates	Recommended	
(a)		(b)	(c)	(d)	(e)	(f)	(g)
Residential						Rate Option A	Rate Option B
Customer Charge		$18.81	$12.42	$14.17	$12.10	$14.00	$27.58
Usage Rates	All Ccf	$0.12061	$0.45616	$0.40680	$0.45616	$0.55702	$0.10435
Commercial							
Customer Charge - Sales		$53.33	$51.11	$59.92	$49.49	$53.33	
Usage Rates	All Ccf	$0.11614				$0.12678	
	First 250		$0.22140	$0.20185	$0.22140		
	All Over 250		$0.19380	$0.17425	$0.19380		
Customer Charge - Transportation		$265.33	$297.11	$305.92		$265.33	
Usage Rates	All Ccf	$0.11614				$0.12678	
	First 250		0.22140	0.20185			
	All Over 250		0.19380	0.17425			
Industrial							
Customer Charge - Sales		$320.96	$153.41	$242.79		$320.96	
Usage Rates	All Ccf	$0.10273				$0.12703	
	First 250		$0.40060	$0.37808			
	All Over 250		$0.37480	$0.35228			
Customer Charge - Transportation		$520.96	$249.73	$432.79		$520.96	
Usage Rates	All Ccf	$0.10273				$0.12703	
	First 250		0.40060	0.37808			
	All Over 250		0.37480	0.35228			

CURRENT AND RECOMMENDED RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CURRENT AND RECOMMENDED RATES

		Current Rates					
Description		CTSA Incorporated and Environs Rates	GCSA Incorporated Rates	GCSA Environs Rates	City of Beaumont Rates	Recommended	
(a)		(b)	(c)	(d)	(e)	(f)	(g)
Public Authority							
Customer Charge - Sales		$81.70	$106.10	$117.78		$81.70	
Usage Rates	All Ccf	$0.11541				$0.12551	
	First 250		$0.15672	$0.13587			
	All Over 250		$0.13092	$0.11007			
Customer Charge - Transportation		$104.70	$302.36	$307.78		$104.70	
Usage Rates	All Ccf	$0.11541				$0.12551	
	First 250		$0.15672	$0.13587			
	All Over 250		$0.13092	$0.11007			
Cogeneration							
Customer Charge - Sales		$104.70	NA	NA		$104.70	
Usage Rates	First 5,000 Ccf	$0.07720				$0.07720	
	Next 35,000	$0.06850				$0.06850	
	Next 60,000	$0.05524				$0.05524	
	All Over 100,000	$0.04016				$0.04016	
Customer Charge - Transportation		$104.70	NA	NA		$104.70	
Usage Rates	First 5,000 Ccf	$0.07720				$0.07720	
	Next 35,000	$0.06850				$0.06850	
	Next 60,000	$0.05524				$0.05524	
	All Over 100, 000	$0.04016				$0.04016	
Public Schools Space Heating							
Customer Charge - Sales		$134.70	NA	NA		$134.70	
Usage Rates	All Ccf	$0.10012				$0.10012	
Customer Charge - Transportation		$234.70	NA	NA		$234.70	
Usage Rates	All Ccf	$0.10012				$0.10012	
Compressed Natural Gas							
Customer Charge - Sales		$192.63	NA	NA		$192.63	
	All Ccf	$0.06684				$0.06684	
Customer Charge - Transportation		$217.63	NA	NA		$217.63	
	All Ccf	$0.06684				$0.06684	

PROOF OF REVENUE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROOF OF REVENUE

					Recommended Rates					
					Customer	Usage	Calculated Revenue at		Assigned	Rounding
Line	Description	Bills	Volumes		Charge	Charges	Recommended Rates		Revenue	Diff.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Residential - Rate Option A	1,961,277			$ 14.00		$ 27,457,883			
2			All Ccf	35,289,483		0.55702	$ 19,656,948			
3	Residential - Rate Option B	1,566,691			$ 27.58		$ 43,209,348			
4			All Ccf	70,309,113		0.10435	$ 7,336,756			
5	Residential Total							$ 97,660,935	$ 97,660,663	$ 272
6										
7	Commercial	169,440			$ 53.33		$ 9,036,231			
8			All Ccf	44,493,619		0.12678	$ 5,640,901	$ 14,677,132		
9										
10	Commercial Transportation	4,385			$ 265.33		$ 1,163,507			
11			All Ccf	20,240,726		0.12678	$ 2,566,119	$ 3,729,627		
12										
13	Commercial Total							$ 18,406,759	$ 18,406,825	$ (66)
14										
15	Industrial	256			$ 320.96		$ 82,137			
16			All Ccf	656,316		0.12703	$ 83,372	$ 165,509		
17										
18	Industrial Transportation	444			$ 520.96		$ 231,306			
19			All Ccf	6,518,433		0.12703	$ 828,036	$ 1,059,343		
20										
21	Industrial Total							$ 1,224,851	$ 1,224,869	$ (17)
22										
23	Public Authority	9,971			$ 81.70		$ 814,624			
24			All Ccf	4,409,183		0.12551	$ 553,397	$ 1,368,021		
25										
26	Public Authority Transportation	4,681			$ 104.70		$ 490,101			
27			All Ccf	7,397,100		0.12551	$ 928,410	$ 1,418,511		
28										
29										

PROOF OF REVENUE

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROOF OF REVENUE

Line	Description	Bills	Volumes		Recommended Rates Customer Charge	Recommended Rates Usage Charges	Calculated Revenue at Recommended Rates		Assigned Revenue	Rounding Diff.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
30	COGEN Transportation	12			$ 104.70		$ 1,256			
31										
32			First 5000	60,000		0.07720	$ 4,632			
33			Next 35,000	420,000		0.06850	$ 28,770			
34			Next 60,000	720,000		0.05524	$ 39,773			
35			Over 100,000	2,685,983		0.04016	$ 107,869	$ 182,300		
36										
37	Public Schools Space Heating	65			$ 134.70		$ 8,709			
38			All Ccf	124,603		0.10012	12475.27645	$ 21,185		
39										
40	Public Schools Space Heating Transportation	980		-	$ 234.70		$ 230,006			
41			All Ccf	1,200,155		0.10012	$ 120,159	$ 350,165		
42										
43	Public Authority Total							$ 3,340,182	$ 3,340,229	$ (47)
44										
45	Compressed Nat. Gas	36			$ 192.63		$ 6,935			
46			All Ccf	620		0.06684	$ 41	$ 6,976		
47	Compressed Nat. Gas Transportation	48			$ 217.63		$ 10,446			
48			All Ccf	1,352,087		0.06684	$ 90,373	$ 100,820		
49	Compressed Nat. Gas Total							$ 107,796	$ 107,796	$ (0)
50										
51	Total Revenue - All Classes									
52	Recommended Rate Revenue							$ 120,740,523	$ 120,740,381	
53	Current Rate Revenue							$ 103,693,715	$ 103,693,715	
54	Revenue Change							$ 17,046,808	$ 17,046,666	$ 142
55	Schedule A - Revenue Deficiency								$ 17,046,666	

CUSTOMER BILL IMPACTS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CUSTOMER BILL IMPACTS

	Year-Round Average Bill				Average January Bill			
			Change				Change	
Description	Current	Recommended	Dollars	%	Current	Recommended	$	%
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Sales Service: (1) (2)								
Residential - Rate Option A								
CTSA Incorporated	$ 29.20	$ 32.33	$ 3.13	10.7%	$ 46.74	$ 63.30	$ 16.56	35.4%
CTSA Environs	$ 29.20	$ 32.33	$ 3.13	10.7%	$ 46.74	$ 63.30	$ 16.56	35.4%
GCSA Incorporated	$ 29.57	$ 32.33	$ 2.76	9.3%	$ 58.55	$ 63.30	$ 4.75	8.1%
GCSA Environs	$ 30.44	$ 32.33	$ 1.89	6.2%	$ 57.91	$ 63.30	$ 5.39	9.3%
City of Beaumont	$ 29.25	$ 32.33	$ 3.08	10.5%	$ 58.23	$ 63.30	$ 5.07	8.7%
Residential - Rate Option B								
CTSA Incorporated	$ 44.71	$ 52.99	$ 8.28	18.5%	$ 88.47	$ 95.91	$ 7.44	8.4%
CTSA Environs	$ 44.71	$ 52.99	$ 8.28	18.5%	$ 88.47	$ 95.91	$ 7.44	8.4%
GCSA Incorporated	$ 55.21	$ 52.99	$ (2.22)	-4.0%	$ 127.48	$ 95.91	$ (31.57)	-24.8%
GCSA Environs	$ 54.74	$ 52.99	$ (1.75)	-3.2%	$ 123.27	$ 95.91	$ (27.36)	-22.2%
City of Beaumont	$ 54.89	$ 52.99	$ (1.90)	-3.5%	$ 127.16	$ 95.91	$ (31.25)	-24.6%
Commercial								
CTSA Incorporated	$ 203.72	$ 207.89	$ 4.17	2.0%	$ 305.97	$ 312.96	$ 6.99	2.3%
CTSA Environs	$ 203.72	$ 207.89	$ 4.17	2.0%	$ 305.97	$ 312.96	$ 6.99	2.3%
GCSA Incorporated	$ 239.47	$ 207.89	$ (31.58)	-13.2%	$ 362.83	$ 312.96	$ (49.87)	-13.7%
GCSA Environs	$ 243.14	$ 207.89	$ (35.25)	-14.5%	$ 363.02	$ 312.96	$ (50.06)	-13.8%
City of Beaumont	$ 237.85	$ 207.89	$ (29.96)	-12.6%	$ 361.21	$ 312.96	$ (48.25)	-13.4%
Industrial								
CTSA Incorporated and Environs	$ 1,755.39	$ 1,831.10	$ 75.71	4.3%	$ 3,245.01	$ 3,399.34	$ 154.33	4.8%
Public Authority								
CTSA Incorporated and Environs	$ 334.64	$ 341.41	$ 6.77	2.0%	$ 655.03	$ 670.39	$ 15.36	2.3%
GCSA Incorporated	$ 390.32	$ 341.41	$ (48.91)	-12.5%	$ 742.16	$ 670.39	$ (71.77)	-9.7%
GCSA Environs	$ 392.78	$ 341.41	$ (51.37)	-13.1%	$ 732.94	$ 670.39	$ (62.55)	-8.5%
Public Schools Space Heating								
CTSA Incorporated and Environs	$ 1,207.53	$ 1,217.59	$ 10.06	0.8%	$ 1,412.18	$ 1,424.16	$ 11.98	0.8%
Compressed Natural Gas								
CTSA Incorporated	$ 201.64	$ 201.73	$ 0.09	0.0%	$ 208.34	$ 208.50	$ 0.16	0.1%

CUSTOMER BILL IMPACTS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CUSTOMER BILL IMPACTS

	Year-Round Average Bill				Average January Bill			
			Change				Change	
Description	Current	Recommended	Dollars	%	Current	Recommended	$	%
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Transportation Service: (3)								
Commercial Transportation								
CTSA Incorporated	$ 2,803.50	$ 2,875.50	$ 72.00	2.6%	$ 3,416.06	$ 3,505.44	$ 89.38	2.6%
CTSA Environs	$ 2,803.50	$ 2,875.50	$ 72.00	2.6%	$ 3,416.06	$ 3,505.44	$ 89.38	2.6%
GCSA Incorporated	$ 3,378.83	$ 2,875.50	$ (503.33)	-14.9%	$ 4,120.91	$ 3,505.44	$ (615.47)	-14.9%
Industrial Transportation								
CTSA Incorporated and Environs	$ 8,397.14	$ 8,826.68	$ 429.54	5.1%	$ 9,410.89	$ 9,895.73	$ 484.84	5.2%
GCSA Incorporated	$ 12,693.43	$ 8,826.68	$ (3,866.75)	-30.5%	$ 14,294.25	$ 9,895.73	$ (4,398.52)	-30.8%
Public Authority Transportation								
CTSA Incorporated and Environs	$ 972.51	$ 996.30	$ 23.79	2.4%	$ 1,382.92	$ 1,417.97	$ 35.05	2.5%
Public School Space Heating Transportation								
CTSA Incorporated and Environs	$ 888.51	$ 894.58	$ 6.07	0.7%	$ 1,404.61	$ 1,415.47	$ 10.86	0.8%
Cogeneration Transportation (4)								
CTSA Incorporated	$ 155,654.46	$ 157,260.17	$ 1,605.71	1.0%	$ 163,214.82	$ 164,899.63	$ 1,684.81	1.0%
Compressed Natural Gas Transportation								
CTSA Incorporated and Environs	$ 14,318.55	$ 14,458.22	$ 139.67	1.0%	$ 13,331.27	$ 13,461.16	$ 129.89	1.0%

CUSTOMER BILL IMPACTS

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

CUSTOMER BILL IMPACTS

	Year-Round Average Bill				Average January Bill			
			Change				Change	
Description	Current	Recommended	Dollars	%	Current	Recommended	$	%
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)

(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:

	CGSA	
	Year-Round	January
Residential - Rate Option A	18	48
Residential - Rate Option B	45	121
Commercial	263	441
Industrial	2,565	5,228
Public Authority	442	1,002
Public School Space Heating	1,927	2,295
Compressed Natural Gas	17	30

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

	CGSA	
	Year-Round	January
Commercial Transportation	4,616	5,730
Industrial Transportation	14,681	16,571
Public Authority Transportation	1,580	2,328
Public School Space Heating Transportation	1,225	2,191
Compressed Natural Gas Transportation	28,168	26,196
	August	January
Cogeneration Transportation	339,785	323,832

(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.

A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of CGSA A/B Rate Relative to Existing CTSA Rates

								$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 18.81	$ 0.12061	$ 0.12061			$ 27.58	$ 0.10435	$ 0.10435	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	23	2,085	$ 225.72	$ -	$ 2.71	$ 225.72	$ 228.43	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ (4.81)	$ (3.99)	-26%	-21%
24	45	2,006	$ 225.72	$ 2.83	$ 5.43	$ 228.55	$ 231.15	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ (3.96)	$ (3.17)	-21%	-16%
46	68	2,578	$ 225.72	$ 5.55	$ 8.14	$ 231.27	$ 233.86	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ (3.14)	$ (2.36)	-16%	-12%
69	90	3,693	$ 225.72	$ 8.26	$ 10.85	$ 233.98	$ 236.57	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ (2.32)	$ (1.54)	-12%	-8%
91	113	4,722	$ 225.72	$ 10.98	$ 13.57	$ 236.70	$ 239.29	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ (1.50)	$ (0.72)	-8%	-4%
114	135	6,110	$ 225.72	$ 13.69	$ 16.28	$ 239.41	$ 242.00	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ (0.68)	$ 0.10	-3%	0%
136	158	7,285	$ 225.72	$ 16.40	$ 19.00	$ 242.12	$ 244.72	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ 0.14	$ 0.92	1%	5%
159	180	8,522	$ 225.72	$ 19.12	$ 21.71	$ 244.84	$ 247.43	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ 0.95	$ 1.74	5%	8%
181	203	10,021	$ 225.72	$ 21.83	$ 24.42	$ 247.55	$ 250.14	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ 1.77	$ 2.55	9%	12%
204	225	11,477	$ 225.72	$ 24.54	$ 27.14	$ 250.26	$ 252.86	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ 2.59	$ 3.37	12%	16%
226	248	12,263	$ 225.72	$ 27.26	$ 29.85	$ 252.98	$ 255.57	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 3.41	$ 4.19	16%	20%
249	270	13,208	$ 225.72	$ 29.97	$ 32.56	$ 255.69	$ 258.28	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 4.23	$ 5.01	20%	23%
271	293	13,691	$ 225.72	$ 32.69	$ 35.28	$ 258.41	$ 261.00	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 5.05	$ 5.83	23%	27%
294	315	13,818	$ 225.72	$ 35.40	$ 37.99	$ 261.12	$ 263.71	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 5.86	$ 6.65	27%	30%
316	338	13,485	$ 225.72	$ 38.11	$ 40.71	$ 263.83	$ 266.43	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 6.68	$ 7.46	30%	34%
339	360	12,886	$ 225.72	$ 40.83	$ 43.42	$ 266.55	$ 269.14	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 7.50	$ 8.28	34%	37%
361	586	78,801	$ 225.72	$ 43.54	$ 70.65	$ 269.26	$ 296.37	$ 330.96	$ 37.67	$ 61.12	$ 368.63	$ 392.08	$ 8.28	$ 7.98	37%	32%
587	812	23,302	$ 225.72	$ 70.77	$ 97.88	$ 296.49	$ 323.60	$ 330.96	$ 61.23	$ 84.68	$ 392.19	$ 415.64	$ 7.97	$ 7.67	32%	28%
813	1,037	6,767	$ 225.72	$ 98.00	$ 125.11	$ 323.72	$ 350.83	$ 330.96	$ 84.79	$ 108.24	$ 415.75	$ 439.20	$ 7.67	$ 7.36	28%	25%
1,038	1,263	2,333	$ 225.72	$ 125.23	$ 152.34	$ 350.95	$ 378.06	$ 330.96	$ 108.35	$ 131.80	$ 439.31	$ 462.76	$ 7.36	$ 7.06	25%	22%
1,264	1,489	1,062	$ 225.72	$ 152.46	$ 179.57	$ 378.18	$ 405.29	$ 330.96	$ 131.90	$ 155.36	$ 462.86	$ 486.32	$ 7.06	$ 6.75	22%	20%
1,490	1,715	585	$ 225.72	$ 179.69	$ 206.79	$ 405.41	$ 432.51	$ 330.96	$ 155.46	$ 178.92	$ 486.42	$ 509.88	$ 6.75	$ 6.45	20%	18%
1,716	1,940	316	$ 225.72	$ 206.92	$ 234.02	$ 432.64	$ 459.74	$ 330.96	$ 179.02	$ 202.47	$ 509.98	$ 533.43	$ 6.45	$ 6.14	18%	16%
1,941	2,166	185	$ 225.72	$ 234.14	$ 261.25	$ 459.86	$ 486.97	$ 330.96	$ 202.58	$ 226.03	$ 533.54	$ 556.99	$ 6.14	$ 5.83	16%	14%
2,167	2,392	122	$ 225.72	$ 261.37	$ 288.48	$ 487.09	$ 514.20	$ 330.96	$ 226.14	$ 249.59	$ 557.10	$ 580.55	$ 5.83	$ 5.53	14%	13%
2,393	2,618	101	$ 225.72	$ 288.60	$ 315.71	$ 514.32	$ 541.43	$ 330.96	$ 249.69	$ 273.15	$ 580.65	$ 604.11	$ 5.53	$ 5.22	13%	12%
2,619	2,843	69	$ 225.72	$ 315.83	$ 342.94	$ 541.55	$ 568.66	$ 330.96	$ 273.25	$ 296.71	$ 604.21	$ 627.67	$ 5.22	$ 4.92	12%	10%
2,844	3,069	41	$ 225.72	$ 343.06	$ 370.17	$ 568.78	$ 595.89	$ 330.96	$ 296.81	$ 320.27	$ 627.77	$ 651.23	$ 4.92	$ 4.61	10%	9%
3,070	3,295	45	$ 225.72	$ 370.29	$ 397.40	$ 596.01	$ 623.12	$ 330.96	$ 320.37	$ 343.82	$ 651.33	$ 674.78	$ 4.61	$ 4.31	9%	8%
3,296	3,521	22	$ 225.72	$ 397.52	$ 424.63	$ 623.24	$ 650.35	$ 330.96	$ 343.93	$ 367.38	$ 674.89	$ 698.34	$ 4.30	$ 4.00	8%	7%
3,522	8,262	70	$ 225.72	$ 424.75	$ 996.44	$ 650.47	$ 1,222.16	$ 330.96	$ 367.49	$ 862.11	$ 698.45	$ 1,193.07	$ 4.00	$ (2.42)	7%	-2%

A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of CGSA A/B Rate Relative to Existing GCSA Incorporated Rates

									$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 12.42	$ 0.45616	$ 0.45616		0		$ 27.58	$ 0.10435	$ 0.10435	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	23	1,478	$ 149.04	$ -	$ 10.26	$ 149.04	$ 159.30	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ 1.58	$ 1.77	13%	13%
24	45	844	$ 149.04	$ 10.72	$ 20.53	$ 159.76	$ 169.57	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ 1.78	$ 1.96	13%	14%
46	68	1,024	$ 149.04	$ 20.98	$ 30.79	$ 170.02	$ 179.83	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ 1.97	$ 2.15	14%	14%
69	90	1,014	$ 149.04	$ 31.25	$ 41.05	$ 180.29	$ 190.09	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ 2.16	$ 2.34	14%	15%
91	113	1,154	$ 149.04	$ 41.51	$ 51.32	$ 190.55	$ 200.36	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ 2.34	$ 2.53	15%	15%
114	135	1,229	$ 149.04	$ 51.77	$ 61.58	$ 200.81	$ 210.62	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ 2.53	$ 2.71	15%	15%
136	158	1,350	$ 149.04	$ 62.04	$ 71.85	$ 211.08	$ 220.89	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ 2.72	$ 2.90	15%	16%
159	180	1,545	$ 149.04	$ 72.30	$ 82.11	$ 221.34	$ 231.15	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ 2.91	$ 3.09	16%	16%
181	203	1,663	$ 149.04	$ 82.56	$ 92.37	$ 231.60	$ 241.41	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ 3.10	$ 3.28	16%	16%
204	225	1,806	$ 149.04	$ 92.83	$ 102.64	$ 241.87	$ 251.68	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ 3.29	$ 3.47	16%	17%
226	248	1,965	$ 149.04	$ 103.09	$ 112.90	$ 252.13	$ 261.94	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 3.48	$ 3.66	17%	17%
249	270	1,976	$ 149.04	$ 113.36	$ 123.16	$ 262.40	$ 272.20	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 3.67	$ 3.85	17%	17%
271	293	2,013	$ 149.04	$ 123.62	$ 133.43	$ 272.66	$ 282.47	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 3.86	$ 4.04	17%	17%
294	315	2,080	$ 149.04	$ 133.88	$ 143.69	$ 282.92	$ 292.73	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 4.05	$ 4.23	17%	17%
316	338	1,911	$ 149.04	$ 144.15	$ 153.95	$ 293.19	$ 302.99	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 4.24	$ 4.42	17%	17%
339	360	1,835	$ 149.04	$ 154.41	$ 164.22	$ 303.45	$ 313.26	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 4.43	$ 4.61	17%	18%
361	468	7,278	$ 149.04	$ 164.67	$ 213.62	$ 313.71	$ 362.66	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 4.58	$ 1.43	18%	5%
469	577	4,181	$ 149.04	$ 214.08	$ 263.02	$ 363.12	$ 412.06	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.40	$ (1.74)	5%	-5%
578	685	2,250	$ 149.04	$ 263.48	$ 312.43	$ 412.52	$ 461.47	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (1.77)	$ (4.92)	-5%	-13%
686	793	1,222	$ 149.04	$ 312.88	$ 361.83	$ 461.92	$ 510.87	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (4.95)	$ (8.09)	-13%	-19%
794	902	593	$ 149.04	$ 362.29	$ 411.23	$ 511.33	$ 560.27	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (8.12)	$ (11.27)	-19%	-24%
903	1010	285	$ 149.04	$ 411.69	$ 460.64	$ 560.73	$ 609.68	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (11.30)	$ (14.45)	-24%	-28%
1,011	1118	188	$ 149.04	$ 461.09	$ 510.04	$ 610.13	$ 659.08	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (14.47)	$ (17.62)	-28%	-32%
1,119	1226	92	$ 149.04	$ 510.50	$ 559.45	$ 659.54	$ 708.49	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (17.65)	$ (20.80)	-32%	-35%
1,227	1335	60	$ 149.04	$ 559.90	$ 608.85	$ 708.94	$ 757.89	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (20.82)	$ (23.97)	-35%	-38%
1,336	1443	36	$ 149.04	$ 609.30	$ 658.25	$ 758.34	$ 807.29	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (24.00)	$ (27.15)	-38%	-40%
1,444	1551	21	$ 149.04	$ 658.71	$ 707.66	$ 807.75	$ 856.70	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (27.18)	$ (30.32)	-40%	-42%
1,552	1660	16	$ 149.04	$ 708.11	$ 757.06	$ 857.15	$ 906.10	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (30.35)	$ (33.50)	-42%	-44%
1,661	1768	11	$ 149.04	$ 757.51	$ 806.46	$ 906.55	$ 955.50	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (33.53)	$ (36.67)	-44%	-46%
1,769	1876	22	$ 149.04	$ 806.92	$ 855.87	$ 955.96	$ 1,004.91	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (36.70)	$ (39.85)	-46%	-48%
1,877	4151	41	$ 149.04	$ 856.32	$ 1,893.34	$ 1,005.36	$ 2,042.38	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (39.88)	$ (106.53)	-48%	-63%

A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of CGSA A/B Rate Relative to Existing GCSA Environs Rates

								$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 14.17	$ 0.40680	$ 0.40680			$ 27.58	$ 0.10435	$ 0.10435	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	23	41	$ 170.04	$ -	$ 9.15	$ 170.04	$ 179.19	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ (0.17)	$ 0.11	-1%	1%
24	45	23	$ 170.04	$ 9.56	$ 18.31	$ 179.60	$ 188.35	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ 0.12	$ 0.39	1%	3%
46	68	28	$ 170.04	$ 18.71	$ 27.46	$ 188.75	$ 197.50	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ 0.41	$ 0.67	3%	4%
69	90	28	$ 170.04	$ 27.87	$ 36.61	$ 197.91	$ 206.65	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ 0.69	$ 0.96	4%	6%
91	113	32	$ 170.04	$ 37.02	$ 45.77	$ 207.06	$ 215.81	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ 0.97	$ 1.24	6%	7%
114	135	34	$ 170.04	$ 46.17	$ 54.92	$ 216.21	$ 224.96	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ 1.25	$ 1.52	7%	8%
136	158	37	$ 170.04	$ 55.32	$ 64.07	$ 225.36	$ 234.11	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ 1.53	$ 1.80	8%	9%
159	180	43	$ 170.04	$ 64.48	$ 73.22	$ 234.52	$ 243.26	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ 1.81	$ 2.08	9%	10%
181	203	46	$ 170.04	$ 73.63	$ 82.38	$ 243.67	$ 252.42	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ 2.10	$ 2.36	10%	11%
204	225	50	$ 170.04	$ 82.78	$ 91.53	$ 252.82	$ 261.57	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ 2.38	$ 2.65	11%	12%
226	248	55	$ 170.04	$ 91.94	$ 100.68	$ 261.98	$ 270.72	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 2.66	$ 2.93	12%	13%
249	270	55	$ 170.04	$ 101.09	$ 109.84	$ 271.13	$ 279.88	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 2.94	$ 3.21	13%	14%
271	293	56	$ 170.04	$ 110.24	$ 118.99	$ 280.28	$ 289.03	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 3.22	$ 3.49	14%	14%
294	315	58	$ 170.04	$ 119.40	$ 128.14	$ 289.44	$ 298.18	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 3.50	$ 3.77	15%	15%
316	338	53	$ 170.04	$ 128.55	$ 137.30	$ 298.59	$ 307.34	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 3.79	$ 4.05	15%	16%
339	360	51	$ 170.04	$ 137.70	$ 146.45	$ 307.74	$ 316.49	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 4.07	$ 4.34	16%	16%
361	468	202	$ 170.04	$ 146.85	$ 190.51	$ 316.89	$ 360.55	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 4.31	$ 1.61	16%	5%
469	577	116	$ 170.04	$ 190.91	$ 234.56	$ 360.95	$ 404.60	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.58	$ (1.12)	5%	-3%
578	685	62	$ 170.04	$ 234.97	$ 278.62	$ 405.01	$ 448.66	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (1.15)	$ (3.85)	-3%	-10%
686	793	34	$ 170.04	$ 279.03	$ 322.68	$ 449.07	$ 492.72	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (3.88)	$ (6.58)	-10%	-16%
794	902	16	$ 170.04	$ 323.09	$ 366.74	$ 493.13	$ 536.78	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (6.61)	$ (9.31)	-16%	-21%
903	1010	8	$ 170.04	$ 367.14	$ 410.79	$ 537.18	$ 580.83	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (9.34)	$ (12.04)	-21%	-25%
1,011	1118	5	$ 170.04	$ 411.20	$ 454.85	$ 581.24	$ 624.89	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (12.07)	$ (14.77)	-25%	-28%
1,119	1226	3	$ 170.04	$ 455.26	$ 498.91	$ 625.30	$ 668.95	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (14.80)	$ (17.50)	-28%	-31%
1,227	1335	2	$ 170.04	$ 499.32	$ 542.97	$ 669.36	$ 713.01	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (17.53)	$ (20.23)	-31%	-34%
1,336	1443	1	$ 170.04	$ 543.37	$ 587.02	$ 713.41	$ 757.06	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (20.26)	$ (22.96)	-34%	-36%
1,444	1551	1	$ 170.04	$ 587.43	$ 631.08	$ 757.47	$ 801.12	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (22.99)	$ (25.69)	-36%	-38%
1,552	1660	0	$ 170.04	$ 631.49	$ 675.14	$ 801.53	$ 845.18	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (25.72)	$ (28.42)	-38%	-40%
1,661	1768	0	$ 170.04	$ 675.55	$ 719.20	$ 845.59	$ 889.24	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (28.44)	$ (31.15)	-40%	-42%
1,769	1876	1	$ 170.04	$ 719.60	$ 763.25	$ 889.64	$ 933.29	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (31.17)	$ (33.88)	-42%	-44%
1,877	4151	1	$ 170.04	$ 763.66	$ 1,688.46	$ 933.70	$ 1,858.50	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (33.90)	$ (91.20)	-44%	-59%

A_B BILL IMPACTS_EXISTING RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of CGSA A/B Rate Relative to Existing City of Beaumont Rates

								$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 12.10	$ 0.45616	$ 0.45616			$ 27.58	$ 0.10435	$ 0.10435	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	23	-	$ 145.20	$ -	$ 10.26	$ 145.20	$ 155.46	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ 1.90	$ 2.09	16%	16%
24	45	-	$ 145.20	$ 10.72	$ 20.53	$ 155.92	$ 165.73	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ 2.10	$ 2.28	16%	16%
46	68	-	$ 145.20	$ 20.98	$ 30.79	$ 166.18	$ 175.99	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ 2.29	$ 2.47	17%	17%
69	90	-	$ 145.20	$ 31.25	$ 41.05	$ 176.45	$ 186.25	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ 2.48	$ 2.66	17%	17%
91	113	-	$ 145.20	$ 41.51	$ 51.32	$ 186.71	$ 196.52	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ 2.66	$ 2.85	17%	17%
114	135	-	$ 145.20	$ 51.77	$ 61.58	$ 196.97	$ 206.78	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ 2.85	$ 3.03	17%	18%
136	158	-	$ 145.20	$ 62.04	$ 71.85	$ 207.24	$ 217.05	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ 3.04	$ 3.22	18%	18%
159	180	-	$ 145.20	$ 72.30	$ 82.11	$ 217.50	$ 227.31	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ 3.23	$ 3.41	18%	18%
181	203	-	$ 145.20	$ 82.56	$ 92.37	$ 227.76	$ 237.57	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ 3.42	$ 3.60	18%	18%
204	225	-	$ 145.20	$ 92.83	$ 102.64	$ 238.03	$ 247.84	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ 3.61	$ 3.79	18%	18%
226	248	-	$ 145.20	$ 103.09	$ 112.90	$ 248.29	$ 258.10	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 3.80	$ 3.98	18%	19%
249	270	-	$ 145.20	$ 113.36	$ 123.16	$ 258.56	$ 268.36	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 3.99	$ 4.17	19%	19%
271	293	-	$ 145.20	$ 123.62	$ 133.43	$ 268.82	$ 278.63	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 4.18	$ 4.36	19%	19%
294	315	-	$ 145.20	$ 133.88	$ 143.69	$ 279.08	$ 288.89	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 4.37	$ 4.55	19%	19%
316	338	1	$ 145.20	$ 144.15	$ 153.95	$ 289.35	$ 299.15	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 4.56	$ 4.74	19%	19%
339	360	-	$ 145.20	$ 154.41	$ 164.22	$ 299.61	$ 309.42	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 4.75	$ 4.93	19%	19%
361	468	-	$ 145.20	$ 164.67	$ 213.62	$ 309.87	$ 358.82	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 4.90	$ 1.75	19%	6%
469	577	-	$ 145.20	$ 214.08	$ 263.02	$ 359.28	$ 408.22	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.72	$ (1.42)	6%	-4%
578	685	-	$ 145.20	$ 263.48	$ 312.43	$ 408.68	$ 457.63	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (1.45)	$ (4.60)	-4%	-12%
686	793	-	$ 145.20	$ 312.88	$ 361.83	$ 458.08	$ 507.03	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (4.63)	$ (7.77)	-12%	-18%
794	902	-	$ 145.20	$ 362.29	$ 411.23	$ 507.49	$ 556.43	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (7.80)	$ (10.95)	-18%	-24%
903	1010	-	$ 145.20	$ 411.69	$ 460.64	$ 556.89	$ 605.84	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (10.98)	$ (14.13)	-24%	-28%
1,011	1118	-	$ 145.20	$ 461.09	$ 510.04	$ 606.29	$ 655.24	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (14.15)	$ (17.30)	-28%	-32%
1,119	1226	-	$ 145.20	$ 510.50	$ 559.45	$ 655.70	$ 704.65	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (17.33)	$ (20.48)	-32%	-35%
1,227	1335	-	$ 145.20	$ 559.90	$ 608.85	$ 705.10	$ 754.05	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (20.50)	$ (23.65)	-35%	-38%
1,336	1443	-	$ 145.20	$ 609.30	$ 658.25	$ 754.50	$ 803.45	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (23.68)	$ (26.83)	-38%	-40%
1,444	1551	-	$ 145.20	$ 658.71	$ 707.66	$ 803.91	$ 852.86	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (26.86)	$ (30.00)	-40%	-42%
1,552	1660	-	$ 145.20	$ 708.11	$ 757.06	$ 853.31	$ 902.26	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (30.03)	$ (33.18)	-42%	-44%
1,661	1768	-	$ 145.20	$ 757.51	$ 806.46	$ 902.71	$ 951.66	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (33.21)	$ (36.35)	-44%	-46%
1,769	1876	-	$ 145.20	$ 806.92	$ 855.87	$ 952.12	$ 1,001.07	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (36.38)	$ (39.53)	-46%	-47%
1,877	4151	-	$ 145.20	$ 856.32	$ 1,893.34	$ 1,001.52	$ 2,038.54	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (39.56)	$ (106.21)	-47%	-63%

A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADIONAL RATE STRUCTURE

Annual Residential Bill Impacts of CGSA A/B Rate Structure in CTSA Compared to Traditional Rate Structure

								$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 18.81	$ 0.29640	$ 0.29640			$ 27.58	$ 0.10435	$ 0.10435	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	23	2,085	$ 225.72	$ -	$ 6.67	$ 225.72	$ 232.39	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ (4.81)	$ (4.32)	-26%	-22%
24	45	2,006	$ 225.72	$ 6.97	$ 13.34	$ 232.69	$ 239.06	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ (4.30)	$ (3.83)	-22%	-19%
46	68	2,578	$ 225.72	$ 13.63	$ 20.01	$ 239.35	$ 245.73	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ (3.81)	$ (3.34)	-19%	-16%
69	90	3,693	$ 225.72	$ 20.30	$ 26.68	$ 246.02	$ 252.40	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ (3.32)	$ (2.86)	-16%	-14%
91	113	4,722	$ 225.72	$ 26.97	$ 33.35	$ 252.69	$ 259.07	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ (2.83)	$ (2.37)	-13%	-11%
114	135	6,110	$ 225.72	$ 33.64	$ 40.01	$ 259.36	$ 265.73	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ (2.34)	$ (1.88)	-11%	-8%
136	158	7,285	$ 225.72	$ 40.31	$ 46.68	$ 266.03	$ 272.40	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ (1.86)	$ (1.39)	-8%	-6%
159	180	8,522	$ 225.72	$ 46.98	$ 53.35	$ 272.70	$ 279.07	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ (1.37)	$ (0.90)	-6%	-4%
181	203	10,021	$ 225.72	$ 53.65	$ 60.02	$ 279.37	$ 285.74	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ (0.88)	$ (0.41)	-4%	-2%
204	225	11,477	$ 225.72	$ 60.32	$ 66.69	$ 286.04	$ 292.41	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ (0.39)	$ 0.08	-2%	0%
226	248	12,263	$ 225.72	$ 66.99	$ 73.36	$ 292.71	$ 299.08	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 0.10	$ 0.57	0%	2%
249	270	13,208	$ 225.72	$ 73.66	$ 80.03	$ 299.38	$ 305.75	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 0.59	$ 1.05	2%	4%
271	293	13,691	$ 225.72	$ 80.32	$ 86.70	$ 306.04	$ 312.42	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 1.08	$ 1.54	4%	6%
294	315	13,818	$ 225.72	$ 86.99	$ 93.37	$ 312.71	$ 319.09	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 1.56	$ 2.03	6%	8%
316	338	13,485	$ 225.72	$ 93.66	$ 100.04	$ 319.38	$ 325.76	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 2.05	$ 2.52	8%	9%
339	360	12,886	$ 225.72	$ 100.33	$ 106.70	$ 326.05	$ 332.42	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 2.54	$ 3.01	9%	11%
361	586	78,801	$ 225.72	$ 107.00	$ 173.62	$ 332.72	$ 399.34	$ 330.96	$ 37.67	$ 61.12	$ 368.63	$ 392.08	$ 2.99	$ (0.60)	11%	-2%
587	812	23,302	$ 225.72	$ 173.92	$ 240.54	$ 399.64	$ 466.26	$ 330.96	$ 61.23	$ 84.68	$ 392.19	$ 415.64	$ (0.62)	$ (4.22)	-2%	-11%
813	1,037	6,767	$ 225.72	$ 240.83	$ 307.45	$ 466.55	$ 533.17	$ 330.96	$ 84.79	$ 108.24	$ 415.75	$ 439.20	$ (4.23)	$ (7.83)	-11%	-18%
1,038	1,263	2,333	$ 225.72	$ 307.75	$ 374.37	$ 533.47	$ 600.09	$ 330.96	$ 108.35	$ 131.80	$ 439.31	$ 462.76	$ (7.85)	$ (11.44)	-18%	-23%
1,264	1,489	1,062	$ 225.72	$ 374.66	$ 441.28	$ 600.38	$ 667.00	$ 330.96	$ 131.90	$ 155.36	$ 462.86	$ 486.32	$ (11.46)	$ (15.06)	-23%	-27%
1,490	1,715	585	$ 225.72	$ 441.58	$ 508.20	$ 667.30	$ 733.92	$ 330.96	$ 155.46	$ 178.92	$ 486.42	$ 509.88	$ (15.07)	$ (18.67)	-27%	-31%
1,716	1,940	316	$ 225.72	$ 508.50	$ 575.11	$ 734.22	$ 800.83	$ 330.96	$ 179.02	$ 202.47	$ 509.98	$ 533.43	$ (18.69)	$ (22.28)	-31%	-33%
1,941	2,166	185	$ 225.72	$ 575.41	$ 642.03	$ 801.13	$ 867.75	$ 330.96	$ 202.58	$ 226.03	$ 533.54	$ 556.99	$ (22.30)	$ (25.90)	-33%	-36%
2,167	2,392	122	$ 225.72	$ 642.33	$ 708.95	$ 868.05	$ 934.67	$ 330.96	$ 226.14	$ 249.59	$ 557.10	$ 580.55	$ (25.91)	$ (29.51)	-36%	-38%
2,393	2,618	101	$ 225.72	$ 709.24	$ 775.86	$ 934.96	$ 1,001.58	$ 330.96	$ 249.69	$ 273.15	$ 580.65	$ 604.11	$ (29.53)	$ (33.12)	-38%	-40%
2,619	2,843	69	$ 225.72	$ 776.16	$ 842.78	$ 1,001.88	$ 1,068.50	$ 330.96	$ 273.25	$ 296.71	$ 604.21	$ 627.67	$ (33.14)	$ (36.74)	-40%	-41%
2,844	3,069	41	$ 225.72	$ 843.07	$ 909.69	$ 1,068.79	$ 1,135.41	$ 330.96	$ 296.81	$ 320.27	$ 627.77	$ 651.23	$ (36.75)	$ (40.35)	-41%	-43%
3,070	3,295	45	$ 225.72	$ 909.99	$ 976.61	$ 1,135.71	$ 1,202.33	$ 330.96	$ 320.37	$ 343.82	$ 651.33	$ 674.78	$ (40.37)	$ (43.96)	-43%	-44%
3,296	3,521	22	$ 225.72	$ 976.91	$ 1,043.53	$ 1,202.63	$ 1,269.25	$ 330.96	$ 343.93	$ 367.38	$ 674.89	$ 698.34	$ (43.98)	$ (47.58)	-44%	-45%
3,522	8,262	70	$ 225.72	$ 1,043.82	$ 2,448.76	$ 1,269.54	$ 2,674.48	$ 330.96	$ 367.49	$ 862.11	$ 698.45	$ 1,193.07	$ (47.59)	$ (123.45)	-45%	-55%

A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADIONAL RATE STRUCTURE

Annual Residential Bill Impacts of CGSA A/B Rate Structure in GCSA Incorporated Compared to Traditional Rate Structure

								$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 18.81	$ 0.29640	$ 0.29640		0	$ 27.58	$ 0.10435	$ 0.10435	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	23	1,478	$ 225.72	$ -	$ 6.67	$ 225.72	$ 232.39	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ (4.81)	$ (4.32)	-26%	-22%
24	45	844	$ 225.72	$ 6.97	$ 13.34	$ 232.69	$ 239.06	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ (4.30)	$ (3.83)	-22%	-19%
46	68	1,024	$ 225.72	$ 13.63	$ 20.01	$ 239.35	$ 245.73	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ (3.81)	$ (3.34)	-19%	-16%
69	90	1,014	$ 225.72	$ 20.30	$ 26.68	$ 246.02	$ 252.40	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ (3.32)	$ (2.86)	-16%	-14%
91	113	1,154	$ 225.72	$ 26.97	$ 33.35	$ 252.69	$ 259.07	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ (2.83)	$ (2.37)	-13%	-11%
114	135	1,229	$ 225.72	$ 33.64	$ 40.01	$ 259.36	$ 265.73	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ (2.34)	$ (1.88)	-11%	-8%
136	158	1,350	$ 225.72	$ 40.31	$ 46.68	$ 266.03	$ 272.40	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ (1.86)	$ (1.39)	-8%	-6%
159	180	1,545	$ 225.72	$ 46.98	$ 53.35	$ 272.70	$ 279.07	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ (1.37)	$ (0.90)	-6%	-4%
181	203	1,663	$ 225.72	$ 53.65	$ 60.02	$ 279.37	$ 285.74	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ (0.88)	$ (0.41)	-4%	-2%
204	225	1,806	$ 225.72	$ 60.32	$ 66.69	$ 286.04	$ 292.41	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ (0.39)	$ 0.08	-2%	0%
226	248	1,965	$ 225.72	$ 66.99	$ 73.36	$ 292.71	$ 299.08	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 0.10	$ 0.57	0%	2%
249	270	1,976	$ 225.72	$ 73.66	$ 80.03	$ 299.38	$ 305.75	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 0.59	$ 1.05	2%	4%
271	293	2,013	$ 225.72	$ 80.32	$ 86.70	$ 306.04	$ 312.42	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 1.08	$ 1.54	4%	6%
294	315	2,080	$ 225.72	$ 86.99	$ 93.37	$ 312.71	$ 319.09	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 1.56	$ 2.03	6%	8%
316	338	1,911	$ 225.72	$ 93.66	$ 100.04	$ 319.38	$ 325.76	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 2.05	$ 2.52	8%	9%
339	360	1,835	$ 225.72	$ 100.33	$ 106.70	$ 326.05	$ 332.42	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 2.54	$ 3.01	9%	11%
361	468	7,278	$ 225.72	$ 107.00	$ 138.80	$ 332.72	$ 364.52	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 2.99	$ 1.28	11%	4%
469	577	4,181	$ 225.72	$ 139.10	$ 170.91	$ 364.82	$ 396.63	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.26	$ (0.46)	4%	-1%
578	685	2,250	$ 225.72	$ 171.20	$ 203.01	$ 396.92	$ 428.73	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (0.47)	$ (2.19)	-1%	-6%
686	793	1,222	$ 225.72	$ 203.30	$ 235.11	$ 429.02	$ 460.83	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (2.21)	$ (3.92)	-6%	-10%
794	902	593	$ 225.72	$ 235.40	$ 267.21	$ 461.12	$ 492.93	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (3.94)	$ (5.66)	-10%	-14%
903	1010	285	$ 225.72	$ 267.51	$ 299.31	$ 493.23	$ 525.03	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (5.67)	$ (7.39)	-14%	-17%
1,011	1118	188	$ 225.72	$ 299.61	$ 331.41	$ 525.33	$ 557.13	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (7.41)	$ (9.12)	-17%	-20%
1,119	1226	92	$ 225.72	$ 331.71	$ 363.51	$ 557.43	$ 589.23	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (9.14)	$ (10.86)	-20%	-22%
1,227	1335	60	$ 225.72	$ 363.81	$ 395.61	$ 589.53	$ 621.33	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (10.87)	$ (12.59)	-22%	-24%
1,336	1443	36	$ 225.72	$ 395.91	$ 427.71	$ 621.63	$ 653.43	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (12.61)	$ (14.32)	-24%	-26%
1,444	1551	21	$ 225.72	$ 428.01	$ 459.81	$ 653.73	$ 685.53	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (14.34)	$ (16.06)	-26%	-28%
1,552	1660	16	$ 225.72	$ 460.11	$ 491.92	$ 685.83	$ 717.64	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (16.07)	$ (17.79)	-28%	-30%
1,661	1768	11	$ 225.72	$ 492.21	$ 524.02	$ 717.93	$ 749.74	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (17.81)	$ (19.52)	-30%	-31%
1,769	1876	22	$ 225.72	$ 524.31	$ 556.12	$ 750.03	$ 781.84	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (19.54)	$ (21.26)	-31%	-33%
1,877	4151	41	$ 225.72	$ 556.41	$ 1,230.24	$ 782.13	$ 1,455.96	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (21.27)	$ (57.66)	-33%	-48%

A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADIONAL RATE STRUCTURE

Annual Residential Bill Impacts of CGSA A/B Rate Structure in GCSA Environs Compared to Traditional Rate Structure

								$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 18.81	$ 0.29640	$ 0.29640			$ 27.58	$ 0.10435	$ 0.10435	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	23	41	$ 225.72	$ -	$ 6.67	$ 225.72	$ 232.39	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ (4.81)	$ (4.32)	-26%	-22%
24	45	23	$ 225.72	$ 6.97	$ 13.34	$ 232.69	$ 239.06	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ (4.30)	$ (3.83)	-22%	-19%
46	68	28	$ 225.72	$ 13.63	$ 20.01	$ 239.35	$ 245.73	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ (3.81)	$ (3.34)	-19%	-16%
69	90	28	$ 225.72	$ 20.30	$ 26.68	$ 246.02	$ 252.40	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ (3.32)	$ (2.86)	-16%	-14%
91	113	32	$ 225.72	$ 26.97	$ 33.35	$ 252.69	$ 259.07	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ (2.83)	$ (2.37)	-13%	-11%
114	135	34	$ 225.72	$ 33.64	$ 40.01	$ 259.36	$ 265.73	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ (2.34)	$ (1.88)	-11%	-8%
136	158	37	$ 225.72	$ 40.31	$ 46.68	$ 266.03	$ 272.40	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ (1.86)	$ (1.39)	-8%	-6%
159	180	43	$ 225.72	$ 46.98	$ 53.35	$ 272.70	$ 279.07	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ (1.37)	$ (0.90)	-6%	-4%
181	203	46	$ 225.72	$ 53.65	$ 60.02	$ 279.37	$ 285.74	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ (0.88)	$ (0.41)	-4%	-2%
204	225	50	$ 225.72	$ 60.32	$ 66.69	$ 286.04	$ 292.41	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ (0.39)	$ 0.08	-2%	0%
226	248	55	$ 225.72	$ 66.99	$ 73.36	$ 292.71	$ 299.08	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 0.10	$ 0.57	0%	2%
249	270	55	$ 225.72	$ 73.66	$ 80.03	$ 299.38	$ 305.75	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 0.59	$ 1.05	2%	4%
271	293	56	$ 225.72	$ 80.32	$ 86.70	$ 306.04	$ 312.42	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 1.08	$ 1.54	4%	6%
294	315	58	$ 225.72	$ 86.99	$ 93.37	$ 312.71	$ 319.09	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 1.56	$ 2.03	6%	8%
316	338	53	$ 225.72	$ 93.66	$ 100.04	$ 319.38	$ 325.76	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 2.05	$ 2.52	8%	9%
339	360	51	$ 225.72	$ 100.33	$ 106.70	$ 326.05	$ 332.42	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 2.54	$ 3.01	9%	11%
361	468	202	$ 225.72	$ 107.00	$ 138.80	$ 332.72	$ 364.52	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 2.99	$ 1.28	11%	4%
469	577	116	$ 225.72	$ 139.10	$ 170.91	$ 364.82	$ 396.63	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.26	$ (0.46)	4%	-1%
578	685	62	$ 225.72	$ 171.20	$ 203.01	$ 396.92	$ 428.73	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (0.47)	$ (2.19)	-1%	-6%
686	793	34	$ 225.72	$ 203.30	$ 235.11	$ 429.02	$ 460.83	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (2.21)	$ (3.92)	-6%	-10%
794	902	16	$ 225.72	$ 235.40	$ 267.21	$ 461.12	$ 492.93	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (3.94)	$ (5.66)	-10%	-14%
903	1010	8	$ 225.72	$ 267.51	$ 299.31	$ 493.23	$ 525.03	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (5.67)	$ (7.39)	-14%	-17%
1,011	1118	5	$ 225.72	$ 299.61	$ 331.41	$ 525.33	$ 557.13	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (7.41)	$ (9.12)	-17%	-20%
1,119	1226	3	$ 225.72	$ 331.71	$ 363.51	$ 557.43	$ 589.23	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (9.14)	$ (10.86)	-20%	-22%
1,227	1335	2	$ 225.72	$ 363.81	$ 395.61	$ 589.53	$ 621.33	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (10.87)	$ (12.59)	-22%	-24%
1,336	1443	1	$ 225.72	$ 395.91	$ 427.71	$ 621.63	$ 653.43	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (12.61)	$ (14.32)	-24%	-26%
1,444	1551	1	$ 225.72	$ 428.01	$ 459.81	$ 653.73	$ 685.53	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (14.34)	$ (16.06)	-26%	-28%
1,552	1660	0	$ 225.72	$ 460.11	$ 491.92	$ 685.83	$ 717.64	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (16.07)	$ (17.79)	-28%	-30%
1,661	1768	0	$ 225.72	$ 492.21	$ 524.02	$ 717.93	$ 749.74	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (17.81)	$ (19.52)	-30%	-31%
1,769	1876	1	$ 225.72	$ 524.31	$ 556.12	$ 750.03	$ 781.84	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (19.54)	$ (21.26)	-31%	-33%
1,877	4151	1	$ 225.72	$ 556.41	$ 1,230.24	$ 782.13	$ 1,455.96	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (21.27)	$ (57.66)	-33%	-48%

A_B BILL IMPACTS_NEW RATES

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PROPOSED A_B STRUCTURE BILL IMPACTS COMPARED TO TRADIONAL RATE STRUCTURE

Annual Residential Bill Impacts of CGSA A/B Rate Structure in City of Beaumont Compared to Traditional Rate Structure

								$ 14.00	$ 0.55702	$ 0.55702	Res A					
			$ 18.81	$ 0.29640	$ 0.29640			$ 27.58	$ 0.10435	$ 0.10435	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	23	-	$ 225.72	$ -	$ 6.67	$ 225.72	$ 232.39	$ 168.00	$ -	$ 12.53	$ 168.00	$ 180.53	$ (4.81)	$ (4.32)	-26%	-22%
24	45	-	$ 225.72	$ 6.97	$ 13.34	$ 232.69	$ 239.06	$ 168.00	$ 13.09	$ 25.07	$ 181.09	$ 193.07	$ (4.30)	$ (3.83)	-22%	-19%
46	68	-	$ 225.72	$ 13.63	$ 20.01	$ 239.35	$ 245.73	$ 168.00	$ 25.62	$ 37.60	$ 193.62	$ 205.60	$ (3.81)	$ (3.34)	-19%	-16%
69	90	-	$ 225.72	$ 20.30	$ 26.68	$ 246.02	$ 252.40	$ 168.00	$ 38.16	$ 50.13	$ 206.16	$ 218.13	$ (3.32)	$ (2.86)	-16%	-14%
91	113	-	$ 225.72	$ 26.97	$ 33.35	$ 252.69	$ 259.07	$ 168.00	$ 50.69	$ 62.66	$ 218.69	$ 230.66	$ (2.83)	$ (2.37)	-13%	-11%
114	135	-	$ 225.72	$ 33.64	$ 40.01	$ 259.36	$ 265.73	$ 168.00	$ 63.22	$ 75.20	$ 231.22	$ 243.20	$ (2.34)	$ (1.88)	-11%	-8%
136	158	-	$ 225.72	$ 40.31	$ 46.68	$ 266.03	$ 272.40	$ 168.00	$ 75.75	$ 87.73	$ 243.75	$ 255.73	$ (1.86)	$ (1.39)	-8%	-6%
159	180	-	$ 225.72	$ 46.98	$ 53.35	$ 272.70	$ 279.07	$ 168.00	$ 88.29	$ 100.26	$ 256.29	$ 268.26	$ (1.37)	$ (0.90)	-6%	-4%
181	203	-	$ 225.72	$ 53.65	$ 60.02	$ 279.37	$ 285.74	$ 168.00	$ 100.82	$ 112.80	$ 268.82	$ 280.80	$ (0.88)	$ (0.41)	-4%	-2%
204	225	-	$ 225.72	$ 60.32	$ 66.69	$ 286.04	$ 292.41	$ 168.00	$ 113.35	$ 125.33	$ 281.35	$ 293.33	$ (0.39)	$ 0.08	-2%	0%
226	248	-	$ 225.72	$ 66.99	$ 73.36	$ 292.71	$ 299.08	$ 168.00	$ 125.89	$ 137.86	$ 293.89	$ 305.86	$ 0.10	$ 0.57	0%	2%
249	270	-	$ 225.72	$ 73.66	$ 80.03	$ 299.38	$ 305.75	$ 168.00	$ 138.42	$ 150.40	$ 306.42	$ 318.40	$ 0.59	$ 1.05	2%	4%
271	293	-	$ 225.72	$ 80.32	$ 86.70	$ 306.04	$ 312.42	$ 168.00	$ 150.95	$ 162.93	$ 318.95	$ 330.93	$ 1.08	$ 1.54	4%	6%
294	315	-	$ 225.72	$ 86.99	$ 93.37	$ 312.71	$ 319.09	$ 168.00	$ 163.49	$ 175.46	$ 331.49	$ 343.46	$ 1.56	$ 2.03	6%	8%
316	338	1	$ 225.72	$ 93.66	$ 100.04	$ 319.38	$ 325.76	$ 168.00	$ 176.02	$ 187.99	$ 344.02	$ 355.99	$ 2.05	$ 2.52	8%	9%
339	360	-	$ 225.72	$ 100.33	$ 106.70	$ 326.05	$ 332.42	$ 168.00	$ 188.55	$ 200.53	$ 356.55	$ 368.53	$ 2.54	$ 3.01	9%	11%
361	468	-	$ 225.72	$ 107.00	$ 138.80	$ 332.72	$ 364.52	$ 330.96	$ 37.67	$ 48.87	$ 368.63	$ 379.83	$ 2.99	$ 1.28	11%	4%
469	577	-	$ 225.72	$ 139.10	$ 170.91	$ 364.82	$ 396.63	$ 330.96	$ 48.97	$ 60.17	$ 379.93	$ 391.13	$ 1.26	$ (0.46)	4%	-1%
578	685	-	$ 225.72	$ 171.20	$ 203.01	$ 396.92	$ 428.73	$ 330.96	$ 60.27	$ 71.47	$ 391.23	$ 402.43	$ (0.47)	$ (2.19)	-1%	-6%
686	793	-	$ 225.72	$ 203.30	$ 235.11	$ 429.02	$ 460.83	$ 330.96	$ 71.57	$ 82.77	$ 402.53	$ 413.73	$ (2.21)	$ (3.92)	-6%	-10%
794	902	-	$ 225.72	$ 235.40	$ 267.21	$ 461.12	$ 492.93	$ 330.96	$ 82.88	$ 94.07	$ 413.84	$ 425.03	$ (3.94)	$ (5.66)	-10%	-14%
903	1010	-	$ 225.72	$ 267.51	$ 299.31	$ 493.23	$ 525.03	$ 330.96	$ 94.18	$ 105.37	$ 425.14	$ 436.33	$ (5.67)	$ (7.39)	-14%	-17%
1,011	1118	-	$ 225.72	$ 299.61	$ 331.41	$ 525.33	$ 557.13	$ 330.96	$ 105.48	$ 116.68	$ 436.44	$ 447.64	$ (7.41)	$ (9.12)	-17%	-20%
1,119	1226	-	$ 225.72	$ 331.71	$ 363.51	$ 557.43	$ 589.23	$ 330.96	$ 116.78	$ 127.98	$ 447.74	$ 458.94	$ (9.14)	$ (10.86)	-20%	-22%
1,227	1335	-	$ 225.72	$ 363.81	$ 395.61	$ 589.53	$ 621.33	$ 330.96	$ 128.08	$ 139.28	$ 459.04	$ 470.24	$ (10.87)	$ (12.59)	-22%	-24%
1,336	1443	-	$ 225.72	$ 395.91	$ 427.71	$ 621.63	$ 653.43	$ 330.96	$ 139.38	$ 150.58	$ 470.34	$ 481.54	$ (12.61)	$ (14.32)	-24%	-26%
1,444	1551	-	$ 225.72	$ 428.01	$ 459.81	$ 653.73	$ 685.53	$ 330.96	$ 150.68	$ 161.88	$ 481.64	$ 492.84	$ (14.34)	$ (16.06)	-26%	-28%
1,552	1660	-	$ 225.72	$ 460.11	$ 491.92	$ 685.83	$ 717.64	$ 330.96	$ 161.99	$ 173.18	$ 492.95	$ 504.14	$ (16.07)	$ (17.79)	-28%	-30%
1,661	1768	-	$ 225.72	$ 492.21	$ 524.02	$ 717.93	$ 749.74	$ 330.96	$ 173.29	$ 184.48	$ 504.25	$ 515.44	$ (17.81)	$ (19.52)	-30%	-31%
1,769	1876	-	$ 225.72	$ 524.31	$ 556.12	$ 750.03	$ 781.84	$ 330.96	$ 184.59	$ 195.79	$ 515.55	$ 526.75	$ (19.54)	$ (21.26)	-31%	-33%
1,877	4151	-	$ 225.72	$ 556.41	$ 1,230.24	$ 782.13	$ 1,455.96	$ 330.96	$ 195.89	$ 433.12	$ 526.85	$ 764.08	$ (21.27)	$ (57.66)	-33%	-48%

RESIDENTIAL

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

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.
				$	97,660,663		3
		Determinants	Recommended				
Bills		3,527,969	Customer Charge		18.81		
Volumes		105,598,596	Usage Rate		0.29640		
			Calculated Revenue		97,660,515.83		
			Rounding		(147)		

A/B Rates						To Implement A/B Rate:		
Rate Option A	*	1,961,277	Customer Charge	$	14.00	1. Input "A" Customer Charge:	$ 14.00	27,457,882.99
	*	35,289,483	Usage Rate	$	0.55702	2. Input "B" Customer Charge:	$ 27.58	43,209,348.15
		17.99				3. Input Initial "B" Usage Charge:	$ 0.00344	241,863.35
		48.39						
						Internally Calculated:		
Rate Option B	*	1,566,691	Customer Charge	$	27.58	4. Calculate "A" Usage Charge:	$ 0.45611	16,095,886.10
	*	70,309,113	Usage Rate	$	0.10435	5. Revenue Requirement Adjustment:	$ 0.10091	10,655,682.52
		44.88						
		120.69						
			Calculated Revenue		97,660,934.96			
			Rounding		272			

*Source: Res Rate Alternatives_CGSA_14.xlsx

COMMERCIAL

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMMERCIAL CLASS RATE DESIGN

Select recommended customer charges.

Proposed Revenue	Class Revenue Alloc.
$ 18,406,825	3

Determinants:	Commercial	Comm. Trans.	Recommended	Commercial	Commercial Trans.
Bills	169,440	4,385	Customer Charge	53.33	265.33
Volumes	44,493,619	20,240,726	Usage Charge	0.12678	0.12678
			Calculated Revenue	$ 18,406,759	
			Rounding	$ (66)	

INDUSTRIAL

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

INDUSTRIAL CLASS RATE DESIGN

Select recommended customer charges.

Proposed Revenue	Class Revenue Alloc.
$ 1,224,869	3

	Industrial	Industrial Trans.	Recommended	Industrial	Industrial Trans.
Determinants:					
Bills	256	444	Customer Charge	320.96	520.96
Volumes	656,316	6,518,433	Usage Rate	0.12703	0.12703
			Calculated Revenue	$ 1,224,851	
			Rounding	$ (17)	

PUBLIC AUTHORITY

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

PUBLIC AUTHORITY CLASS RATE DESIGN

Select recommended customer charges.

	Proposed Revenue	Class Revenue Alloc.
	$ 3,340,229	3

	Public Authority	Public Authority Trans.	Cogeneration Transportation			Pub. Sch. Spc. Htg.	Pub. Sch. Spc. Htg. Trans.
Determinants:							
Bills	9,971	4,681			12	65	980
Volumes	4,409,183	7,397,100			3,885,983	124,603	1,200,155
			First 5,000 Ccf		60,000		
			Next 35,000		420,000		
			Next 60,000		720,000		
			All Over 100,000		2,685,983		
			Customer Charge	$	104.70		
			First 5,000 Ccf		0.07720		
			Next 35,000		0.06850		
			Next 60,000		0.05524		
			All Over 100,000		0.04016		
Recommended Customer Charge	$ 81.70	$ 104.70		$	104.70	$ 134.70	$ 234.70
Volumes	0.12551	$ 0.12551	First 5,000 Ccf		0.07720	0.10012	$ 0.10012
			Next 35,000		0.06850		
			Next 60,000		0.05524		
			All Over 100,000		0.04016		
						$ 21,185	$ 350,165
Calculated Revenue	$ 1,368,021	$ 1,418,511		Total	182,300.28	Total	$ 371,350
						Total Calculated Revenue	3,340,182
						Rounding	(47)

Cogeneration Transportation

Current Revenue		182,300
Revenue Change %		0.00%
Revenue Change	$	-
Customer Charge Rev. Change	$	-
Required Volumetric Rev. Change	$	-
Volumetric Rate Change		0

CNG

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED JUNE 30, 2019
UPDATED FOR KNOWN AND MEASURABLE CHANGES THROUGH SEPTEMBER 30, 2019

COMPRESSED NATURAL GAS CLASS RATE DESIGN

Select recommended customer charges.

Proposed Revenue	Class Revenue Alloc.
$ 107,796	3

Determinants:	CNG	CNG Trans.	Recommended		CNG	CNG Trans.
Bills	36	48	Customer Charge		192.63	217.63
Volumes	620	1,352,087	Usage Charge		0.06684	0.06684
			Calculated Revenue	$	107,796	
			Rounding	$	(0)	

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.

WORKPAPERS

TO

DIRECT TESTIMONY

OF

G. DAVID SCALF

The workpapers to the Direct Testimony of G. David Scalf that are Confidential will be provided pursuant to the Protective Agreement.

RAILROAD COMMISSION OF TEXAS
OFFICE OF GENERAL COUNSEL

December 15, 2010

TO ALL PARTIES OF RECORD

Re: Gas Utilities Docket No. 9988; 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

SIGNED ORDER

Please find attached a copy of the Order signed by the Commissioners in open conference on Tuesday, December 14, 2010, regarding the above-referenced docket.

Sincerely,

Loretta Howard

Loretta Howard
Legal Secretary

Attachment

RAILROAD COMMISSION OF TEXAS

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.	§ § § § § § §	**GAS UTILITIES DOCKET NO. 9988**

FINAL ORDER

Notice of Open Meeting to consider this Order was duly posted with the Secretary of State within the time period provided by law pursuant to TEX. GOV'T CODE ANN. Chapter 551, et seq. (Vernon 2004 & Supp. 2008). The Railroad Commission of Texas adopts the following findings of fact and conclusions of law and orders as follows:

FINDINGS OF FACT

1. Texas Gas Service Company ("TGS") is a utility as that term is defined in the Texas Utility Code, and is subject to the jurisdiction of the Railroad Commission of Texas ("Commission").

2. TGS owns and operates a gas distribution system that provides gas service to customers in its El Paso Service Area ("EPSA").

3. The EPSA includes the Cities of El Paso, Anthony, Clint, Horizon City, Socorro, and Vinton, Texas.

3. On May 12, 2010, TGS filed a Petition for Review with the Railroad Commission of Texas ("Commission") to appeal the rate-setting action of the City of El Paso, Texas ("El Paso" or the "City") which denied TGS' request for a rate increase within the jurisdiction of the City. This Petition for Review was docketed by the Commission as Gas Utilities Docket No. 9988. On May 24, 2010, TGS filed a Petition for Review appealing the rate-setting actions of the municipalities of Anthony, Clint, Horizon City, Socorro, and Vinton, Texas, which denied TGS' requests for rate increases within their respective municipal boundaries, and was docketed by the Commission as Gas Utilities Docket No. 9992.

4. The Hearings Examiner consolidated GUD Nos. 9988 and 9992 into one docket pursuant to TEX. ADMIN. CODE §1.125 (1991) on June 3, 2010.

5. On June 3, 2010, Staff of the Railroad Commission of Texas ("Staff") and the City of El Paso, Texas (the "City") intervened in this proceeding. On June 17, 2010, the State of Texas' agencies and institutions of higher learning, represented by the Attorney General of Texas, Consumer Protection Division ("State"), intervened in this proceeding. On June 25, 2010, ArcelorMittal Vinton, Inc., intervened in this proceeding. No other parties and or individuals files letters of protest, objections, moved to intervene, or otherwise participated in this docket before the Commission.

6. The final hearing in this matter was conducted in Austin, Texas on August 31, 2010 through September 3, 2010.

7. By written agreement and as stated at the hearing TGS agreed to extend the statutory deadline for Commission action on this docket until December 16, 2010.

Rate Base

8. TGS adjusted its cost of service model for known and measurable changes through December 31, 2010. TGS included in its filing projected plant additions through June 30, 2010, and on June 25, 2010 updated this with actual plant-in-service balances for the months of April and May.

9. The June 25, 2010, filing reduced the Company's requested base rate revenue increase by $195,617 and reduced gross plant to $216,424,630 and net plant to $138,008,370.

10. TGS' June 25, 2010, filing was reasonable because it updated projected data with actual in-service amounts, and was filed before the discovery period had ended, 6 weeks before intervenor testimony was due, and 9-1/2 weeks before the hearing on the merits, and therefore gave Staff of the Commission and intervenors appropriate notice of the updated data and time to review the data before the final hearing on the merits.

11. TGS did not conduct a lead-lag study for the underlying municipal rate request or this appeal. TGS proposes to use a zero Cash Working Capital balance and therefore no corresponding adjustment to its Rate Base.

12. It is reasonable under the circumstances of this proceeding for TGS to not conduct a lead-lag study and to utilize a zero Cash Working Capital balance because a zero balance is consistent with the applicable FERC rule regarding the absence of a lead-lag study; will result in lower rate case expenses; and had TGS conducted a lead-lag study there is a higher probability that it would have shown a positive balance as opposed to a negative balance. TGS would likely be able to calculate a positive CWC balance had the Company prepared a lead-lag study for this docket. It is therefore reasonable to request a zero balance CWC in lieu of conducting a lead-lag study and incurring the associated expense.

13. TGS proposal to allocate ADFIT using a net-plant based factor is reasonable because allocations based on gross plant may distort the proportion of each jurisdiction's responsibility for the ADFIT balance. Net-plant recognizes these factors and is the more appropriate basis to allocate ADFIT.

14. It is reasonable to reduce TGS' rate base by $203,921 because the Commission previously approved an alternative method for the Company to recoup line extension costs through monthly surcharges billed to specific low-income residences These costs are recouped over a longer period of time, on a monthly basis, with a lower rate impact. Because these costs are recovered through monthly tapping fees, they should not be included in TGS' rate base.

Capital Structure and Rate of Return

14. A capital structure of 59.24% common equity and 40.76% long-term debt is reasonable for TGS.

15. A cost of long-term debt for TGS of 6.21% is reasonable for TGS.

16. A cost of equity of 10.33% for TGS is reasonable.

17. A rate of return on invested capital of 8.65% is reasonable for TGS.

Expenses

18. TGS' proposed short-term incentive compensation expense is unreasonable because it primarily determines the amount of incentive compensation an employee is able to receive using factors that are not related to safety and uses methods related to the financial performance of its parent company, ONEOK, Inc. It is reasonable for TGS to recover 10 percent of its requested short term incentive compensation because 10 percent of the potential award is based on safety metrics.

19. TGS' proposed long-term incentive compensation expense is unreasonable because it primarily determines the amount of incentive compensation an employee is able to receive using factors that are not related to safety and uses methods related to the financial performance of its parent company, ONEOK, Inc.

20. TGS is requesting recovery of $168,386 in expenses incurred for the Company's Supplemental Executive Retirement Plan ("SERP"). TGS' proposed SERP expense is unreasonable because it is not necessary for the provision of safe gas service to the public.

21. TGS is requesting recovery of $113,091 in expenses incurred for the Company's Employee Stock Purchase Program ("ESPP"). TGS' ESPP expense is unreasonable because it is not necessary for the provision of safe gas service to the public.

22. TGS' alternative proposal to recover Pipeline Integrity Expenses through a separate tariff rider, coupled with regulatory review of the reasonableness and necessity of the costs incurred and passed through, is the best mechanism for recovery of these expenses and is reasonable.

23. TGS' proposed recovery of allocated corporate and division expenses are reasonable.

24. TGS' proposed use of the modified Distrigas Allocation Methodology is reasonable.

25. TGS proposes amortizing reserve imbalance over the remaining lives of the assets. This approach is reasonable and in accordance with rate-making principles

26. TGS' proposed injuries and damages expense is unreasonable. It is reasonable to normalize this expense over a four-year period of time and to reduce this amount by $146,638 for establishing the Company's cost of service.

27. TGS requests $217,741 of employee travel and meals expense be included in the revenue requirement. This expense is disallowed because TGS did not prove the expense to be reasonable, necessary and directly related to the provision of gas service to customers in the EPSA. TGS' supporting documentation of these expenses was inadequate for regulatory review.

Revenues

28. During the 10-year period from 2000-2009, the sum of the deviations based on the 10-year measure of normal is zero Heating Degree Days for the El Paso Service Area. The sum of the deviations during the 2000-2009 period based on the 30-year measure of normal is negative 1,563 Heating Degree Days for the El Paso Service Area. The 10-year period is a more appropriate measure of ongoing weather conditions than the 30-year period for normalizing gas sales revenues.

29. TGS' proposal to normalize gas sales revenues for weather using a 10-year period is reasonable for the El Paso Service Area.

30. TGS' proposal to use the test year amount, updated to December 31, 2009, of $1,192,680 for account 4880, Service Fees is reasonable for rate-making purposes because this value is reasonably representative of expected service fee revenue in the future and when the rates set in this proceeding are likely to be in effect.

Rate Design

31. TGS proposed using zero intercept study, checked by a minimum distribution system study, to allocate costs of distribution mains. The proposed methodology is reasonable and the resulting classification of distribution mains investment as 63.12 percent customer-related and 36.88 percent demand-related is reasonable.

32. TGS proposed classifying Transmission Plant as 100 percent demand related. Classifying Transmission Plant as 100 percent demand related is reasonable for the EPSA.

33. TGS' proposed rate designs are not reasonable. The rates, as shown on the attached rate schedule, consisting of a monthly customer charge and volumetric charges are reasonable.

34. TGS requested approval of tariffs consistent with the utility's proposed rates. TGS' proposed tariffs are not reasonable because they reflect rates inconsistent with the rates determined to be just and reasonable under this order. The attached tariffs reflect the rates approved herein and are reasonable.

CONCLUSIONS OF LAW

1. Texas Gas Service Company (TGS) is a "Gas Utility" as defined in TEX. UTIL. CODE ANN. §101.003(7) and §121.001 (Vernon 2007 & Supp. 2010) and is therefore subject to the jurisdiction of the Railroad Commission (Commission) of Texas.

2. The Commission has jurisdiction over TGS and TGS' petition for *de novo* review under TEX. UTIL. CODE ANN. §§ 102.001, 103.051, 103.054, 103.055, 104.001 and 104.201 (Vernon 2007 & Supp. 2008).

3. The Appeals were processed in accordance with the requirements of the Gas Utility regulatory Act (GURA), and the Administrative Procedure Act, TEX. GOV'T CODE ANN. §§2001.001-2001.902 (Vernon 2000 and Supp. 2004) (APA).

4. In accordance with the stated purpose of the Texas Utilities Code, Subtitle A, expressed under TEX. UTIL. CODE ANN. §101.002 (Vernon 1998), the Commission has assured that the rates, operations, and services established in this docket are just and reasonable to customers and to the utilities.

5. In accordance with 16 TEX. ADMIN. CODE ANN.§7.235 (2002), adequate notice was properly provided.

6. In accordance with the provisions of TEX. UTIL. CODE ANN. §103.051 and §103.054 (Vernon 2007 & Supp. 2010) TGS timely appealed the actions of the Cities Cities of El Paso, Anthony, Clint, Horizon City, Socorro, and Vinton, Texas, by filing petitions for review with Railroad Commission of Texas.

7. TGS failed to meet its burden of proof in accordance with the provisions of TEX. UTIL. CODE ANN. §104.008 (Vernon 2007 & Supp. 2010) on the elements of its requested rate increase identified in this order.

8. The revenue, rates, rate design, tariffs, and service charges proposed by TGS are found to be not just and reasonable, unreasonably preferential, prejudicial, or discriminatory, and are not sufficient, equitable, and consistent in application to each class of consumer, as required by TEX. UTIL. CODE ANN. §104.003 (Vernon 2007 & Supp. 2010).

9. The revenue, rates, rate design, tariffs, and service charges proposed by TGS, as amended by the Commission and identified in the schedules attached to this order, are just and reasonable, are not unreasonably preferential, prejudicial, or discriminatory, and are sufficient, equitable, and consistent in application to each class of consumer, as required by TEX. UTIL. CODE ANN. §104.003 (Vernon 2007 & Supp. 2010).

10. The overall revenues as established by the findings of fact and attached schedules and tariffs are reasonable; fix an overall level of revenues for TGS that will permit the company a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public over and above its reasonable and necessary operating expenses, as required by TEX. UTIL. CODE ANN. § 104.051 (Vernon 2007 & Supp. 2010); and otherwise comply with Chapter 104 of the Texas Utilities Code.

11. The revenue, rates, rate design, tariffs, and service charges proposed will not yield to TGS more than a fair return on the adjusted value of the invested capital used and useful in rendering service to the public to the public, as required by TEX. UTIL. CODE ANN. § 104.052 (Vernon 2007 & Supp. 2010).

12. The rates established in this docket comport with the requirements of TEX. UTIL. CODE ANN. §104.053 (Vernon 2007 & Supp. 2010) and are based upon the adjusted value of invested capital used and useful, where the adjusted value is a reasonable balance between the original cost, less depreciation, and current cost, less adjustment for present age and condition.

13. In accordance with TEX. UTIL. CODE ANN. §104.054 (Vernon 2007 & Supp. 2010) and TEX. ADMIN. CODE §7.5252, book depreciation and amortization was calculated on a straight line basis over the useful life expectancy of TGS's property and facilities.

14. In this proceeding, TGS has the burden of proof under TEX. UTIL. CODE ANN. §104.008 (Vernon 2007 & Supp. 2010) to show that the proposed rate changes are just and reasonable.

15. Rate case expenses for GUD No. 9988 will be considered by the Commission in accordance with TEX. UTIL. CODE ANN. §104.008 (Vernon 2007 & Supp. 2010), and 16 TEX. ADMIN. CODE §7.5530 (2002), in a separate proceeding.

16. All expenses for lost and unaccounted for gas in excess of 5.0 percent shall be disallowed, consistent with TEX. ADMIN. CODE § 7.5519 (2002).

17. TGS is required by 16 TEX. ADMIN. CODE §7.315 (2002) to file electronic tariffs incorporating rates consistent with this Order within thirty days of the date of this Order.

18. The rate setting methodologies set forth in TEX. UTIL. CODE ANN. §104.051 et seq. were used to set the rates in this proceeding.

IT IS THEREFORE ORDERED that Texas Gas Service Company's proposed schedule of rates is hereby **DENIED.**

IT IS FURTHER ORDERED that the rates, rate design, tariffs and service charges established in the findings of fact and conclusions of law and in the Examiners' Recommendation shown on the attached Schedules and tariffs for Texas Gas Service Company are **APPROVED**.

IT IS FURTHER ORDERED that a separate gas utility docket be opened in order to determine the appropriate tariff rider for the recovery of pipeline integrity testing expenses.

IT IS FURTHER ORDERED that, in accordance with 16 TEX. ADMIN. CODE §7.315, within 30 days of the date this Order is signed, Texas Gas Service Company shall file tariffs with the Gas Services Division. The tariffs shall incorporate rates, rate design, tariffs and service charges consistent with this Order, as stated in the findings of fact and conclusions of law and shown in the Examiners' Recommendation on the attached

Schedules and tariffs.

IT IS FURTHER ORDERED that any proposed findings of fact and conclusions of law not specifically adopted herein are **DENIED**. **IT IS ALSO ORDERED** that each exception to the Examiners' Proposal for Decision not expressly granted herein is overruled and all pending motions and requests for relief not previously granted herein are hereby **DENIED**.

IT IS FURTHER ORDERED THAT this Order will not be final and appealable until 20 days after a party is notified of the Commission's order. A party is presumed to have been notified of the Commission's order three days after the date on which the notice is actually mailed. If a timely motion for rehearing is filed by any party at interest, this order shall not become final and effective until such motion is overruled, or if such motion is granted, this order shall be subject to further action by the Commission. Pursuant to TEX. GOV'T CODE §2001.146(e), the time allotted for Commission action on a motion for rehearing in this case prior to its being overruled by operation of law, is hereby extended until 90 days from the date the order is served on the parties.

Each exception to the examiners' proposal for decision not expressly granted herein is overruled. All requested findings of fact and conclusions of law which are not expressly adopted herein are denied. All pending motions and requests for relief not previously granted or granted herein are denied.

SIGNED this 14th day of December, 2010.

RAILROAD COMMISSION OF TEXAS

CHAIRMAN VICTOR CARRILLO

COMMISSIONER ELIZABETH A. JONES

COMMISSIONER MICHAEL L. WILLIAMS

ATTEST:

SECRETARY

RAILROAD COMMISSION OF TEXAS

OFFICE OF GENERAL COUNSEL

April 19, 2011

TO ALL PARTIES OF RECORD

Re: Gas Utilities Docket No. 10000; Statement of Intent Filed to Change the Rate CGS and Rate PT of Atmos Pipeline - Texas

SIGNED ORDER

Please find attached a copy of the Order signed by the Commissioners in open conference on Monday, April 18, 2011, regarding the above-referenced docket.

Sincerely,

Loretta Howard

Loretta Howard
Legal Secretary

Attachment

BEFORE THE
RAILROAD COMMISSION OF TEXAS

STATEMENT OF INTENT OF INTENT TO CHANGE THE RATE CGS AND RATE PT OF ATMOS PIPELINE - TEXAS	**§ § § §**	**GAS UTILITIES DOCKET No. 10000**

FINAL ORDER

Notice of Open Meeting to consider this Order was duly posted with the Secretary of State within the time period provided by law pursuant to TEX. GOV'T CODE ANN. CHAP 551, *et seq*. (Vernon 2004 & Supp. 2010). The Railroad Commission adopts the following findings of fact and conclusions of law and orders as follows:

FINDINGS OF FACT

1. Atmos Pipeline – Texas ("Applicant" or "Company"), a division of Atmos Energy Corporation is a gas utility as that term is defined in the Texas Utility Code.

2. On September 17, 2010, Atmos Pipeline – Texas filed a *Statement of Intent* to change its Rate CGS and Rate PT and related riders.

3. The implementation of the proposed rates was suspended on October 12, 2010.

4. Notice of the Hearing was given to all parties entitled to notice and the hearing in this matter commenced on January 24, 2011.

5. Atmos Pipeline – Texas is an unincorporated division of Atmos Energy Corporation and is an intrastate natural gas transmission pipeline operating solely in Texas. Atmos Pipeline – Texas operates a large intrastate pipeline consisting of approximately 6,000 miles of transmission pipeline, approximately 700 city gate meters, five underground storage facilities, and forty-one (41) gas compressor stations. The geographical areas served by this pipeline division spans from the area bounded by the Oklahoma border; the Katy hub near Houston; the Carthage hub in East Texas; the Waha hub in West Texas; and the Austin/Hill Country area.

6. Atmos Pipeline – Texas provides service to three customer classes.

    a. Atmos Pipeline – Texas provides transportation and storage service to the local distribution companies (LDC). The customers in this group are served pursuant to two tariffs: Rate CGS-Mid-Tex and Rate CGS-Other.

b. The customers in this class are served pursuant to the Pipeline Transportation Tariff Rate PT-Pipeline Transportation. These are interruptible customers and are under cost of service rates set by the Commission because they do not have viable competitive alternatives to Atmos Pipeline – Texas.

c. Third, Atmos Pipeline-Texas provides services to certain industrial customers, electric generation customers, producers and marketer transportation customers (also referred to as through-system deliveries) that are served under negotiated rates. The third category of customers in this filing is the Other Revenue segment. The rates paid by these customers are negotiated rates and are not set in this proceeding.

d. Atmos Pipeline – Texas also provides ancillary services to producers and marketers, such as storage.

7. The total throughput during the test year for the regulated customers subject to the rates set in this case was distributed among the two regulated classes of customers as follows:

a. Rate CGS: 91.71%.

b. Pipeline Transportation Rate PT: 8.29%.

8. The Atmos Pipeline – Texas system is designed to meet the peak-day demands of human needs customers.

9. The test year in this case was the 12-month period ending March 31, 2010.

Books and Records

10. Atmos Pipeline – Texas maintains its books and records in accordance with the requirements of the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts.

Section 102.051 Review

11. A gas utility must file a report with the Railroad Commission regarding the sale, acquisition, or lease of a plant or for a total consideration of more than $1 million dollars or regarding a merger or consolidation with another gas utility operating in this state.

12. Atmos Energy Corporation filed a report with the Railroad Commission after the merger.

13. The report was docketed as GUD No. 9555, Application for Review of Merger Between Atmos Energy Corporation and TXU Gas Company, Ltd.

14. In GUD No. 9555, the Commission explicitly deferred consideration of the transaction under section 102.051, of the Texas Utilities Code, until this proceeding. The merger

was previously considered in GUD No. 9670 and found to be just and reasonable and consistent with the public interest.

15. In reviewing the public interest consideration the Commission considered the following factors: (1) The reasonable value of property, facilities, or securities; (2) investments made to enhance or improve reliability; (3) actions implemented to enhance or improve safety; (4) efforts to enhance or improve customer service quality; (5) measures accomplished for improvements to operations, management, and administrative process; (6) community benefits resulting from the acquisition; (7) impacts on bond ratings and investment community's view of the acquisition; (8) efficiencies and economies of scope and scale resulting from the acquisition; (9) liability avoidance or mitigation as a result of the acquisition; and, (10) effect on customer rates.

16. In light of the factors set forth in Finding of Fact No. 15, the merger between Atmos Energy Corporation and TXU Gas Company, Ltd. was consistent with the public interest.

Interim Rate Adjustments

17. Atmos Pipeline – Texas made seven interim rate adjustments that were considered in these proceedings pursuant to the interim rate adjustment provisions of TEX. UTIL. CODE ANN. § 104.301. Those cases were docketed as GUD Nos. 9560, 9615, 9664, 9726, 9788, 9855, 9950.

18. The Earnings Monitoring Reports that were filed with the interim rate adjustments referenced in Finding of Fact No. 17 above were properly filed by Atmos Pipeline – Texas.

19. The allocation of Shared Services included in the interim rate adjustment filings considered in this proceeding was just and reasonable.

20. The *ad valorem* taxes included in certain of the interim rate adjustments considered in this proceeding was not correctly calculated and a refund in the amount of $1,134,253, should be made as set out in the attached schedule, Ad Valorem Tax GRIP Refund by Customer Class Plus Interest.

21. It is reasonable to have the refund ordered as part of this docket as a one-time refund to the Rate CGS and Rate PT customers.

22. Atmos Pipeline – Texas did not over-earn on the allowable rate of return.

23. Expenses related to computers included in the interim rate adjustment filings considered in this case were reasonable and necessary to the operation of Atmos Pipeline – Texas.

24. Interim rate adjustment filings made at the Railroad Commission are available for inspection by any interested party.

25. Interim rate adjustment filings include a level of detailed information not normally included in *Statement of Intent* cases.

26. The proceeding in this case allowed the parties an opportunity to review and challenge investments included in the interim rate adjustment filings considered in this case and it is not necessary to revise those procedures in future cases.

27. In order to avoid controversy, Atmos Pipeline – Texas removed certain items from several the interim rate adjustment filings that were considered in this case.

28. Atmos Pipeline – Texas included several of the previously removed items referenced in Finding of Fact No. 27 as part of its rate base calculation in this proceeding.

29. Except for the adjustment made in Finding of Fact Nos. 32 to 40 below, the capital investments included in the interim rate adjustment filings considered in this proceeding were just and reasonable.

30. Amounts voluntarily excluded from interim rate adjustment filings may be included in future *Statement of Intent* proceedings.

31. All capital investment included in the seven interim rate adjustment filings are subject to review and subject to refund.

32. Atmos Pipeline – Texas has not established that the inclusion of meals, entertainment, lodging, travel in the Cost of Service using a threshold of $50 per meal per person and $250 per nights lodging expense is reasonable.

33. It is reasonable to include meals up to $25 and under per meal per person and lodging up to $150 and under per night in the Cost of Service. It is reasonable that these limitations be exclusive of taxes.

34. Atmos Pipeline – Texas has not established, in this case, that it is reasonable to include in the Cost of Service any meal expense over $25 and lodging expense over $150.

35. It is reasonable to require a detailed receipt for all meals and lodging expenses included in the Cost of Service.

36. The removal of an additional $51,687 in meals from the Cost of Service is reasonable.

37. Atmos Pipeline – Texas has not established that the inclusion of artwork in the Cost of Service is reasonable.

38. The removal of $46,552 in artwork is reasonable.

39. Atmos Pipeline – Texas has not established that the allocated cost from Shared Service for the Mississippi Billing system is reasonable.

40. The removal of $7,174 for Project No. 010.11279 for the Mississippi Billing System is reasonable.

Rate Base

41. The proposed level of adjusted rate base included by Atmos Pipeline – Texas in this case is not reasonable.

42. The calculations of accumulated deferred income taxes, as reflected in the attached schedules, are just and reasonable.

43. Atmos Pipeline – Texas correctly adjusted the charitable contribution carryover included in its calculation of accumulated deferred income taxes.

44. Atmos Pipeline – Texas included an advance payment for compressor equipment in its rate base calculation.

45. The advance payments should have been included in construction work in progress.

46. No showing was made that an allowance for construction work in progress is required in this case and accordingly the prepayments for compressor equipment may not be included in the company's calculation of base rates.

47. Atmos Pipeline – Texas did not establish that the funds collected for FAS 106 are restricted or dedicated to FAS 106 and it is reasonable that an external fund be established as has been the case for the other states where Atmos Energy Corporation conducts business.

48. The FAS 106 liability calculation reflected on the attached schedules is just and reasonable.

49. It is reasonable for Atmos Pipeline – Texas to use a 13-month average ended March 31, 2010, to determine Working Gas in Storage value.

50. It is reasonable that the 13-month average for Working Gas in Storage is $150,781,860, for the cost of service calculation in this proceeding.

51. It is not reasonable to presume NYMEX futures is a benchmark for determining physical delivery prices for the purpose of determining the prices a utility might pay for gas for future periods.

52. It is not reasonable to extend the test-year period for one or more accounts to manipulate the results.

53. The Working Gas in Storage calculation reflected on the attached schedules is just and reasonable.

54. An adjustment to the revenue lag is reasonable if the revenue from the non-regulated customers is treated as a credit in this proceeding as it is not reasonable to include the revenue lag days for the non-regulated transportation customers in the calculation of the revenue lag for Atmos Mid – Tex.

55. The cash working capital calculations reflected on the attached schedules is just and reasonable.

Shared Service Unit Allocation

56. Atmos Pipeline – Texas employees a four factor allocation methodology to allocate general plant, materials and supplies, accumulated deferred income taxes, injuries and damages reserve and certain adjustments to rate base.

57. The components of the four factor formula are gross direct property and equipment, number of customers, operating expenses, and operating income.

58. The methodology has been previously adopted by the Railroad Commission for allocation of costs to Atmos Mid – Tex and produces a reasonable allocation of costs.

Operating Expenses

59. Base labor expenses of Atmos Pipeline – Texas employees is derived from the following operating division: Direct labor expenses from Atmos Pipeline – Texas employees, Atmos Mid – Tex, and Shared Services labor allocated to Atmos Pipeline – Texas.

60. Atmos Pipeline – Texas did not establish that an adjustment to the test-year level of base-labor expenses was just and reasonable as the increasing trend of test-year expenses is accurately captured in the test-year data.

61. Rates are typically based upon test-year data and the Railroad Commission has previously established payroll expenses based upon the test-year level of expenses.

62. Atmos Pipeline – Texas established that the proposed adjustment due to merit increases made after the end of the test year was a known and measurable change and it is appropriate to make an adjustment to reflect that change.

63. Atmos Pipeline – Texas did not accurately calculate the adjustment because the adjustment made did not reflect the fact that Atmos Pipeline – Texas provides labor to other divisions of Atmos Energy Corporation. Those labor expenses are charged to those over divisions.

64. Atmos Pipeline – Texas has established that the medical and dental expenses incurred during the test year are just and reasonable.

65. Atmos Pipeline – Texas has established that the overtime expense level established during the test year is just and reasonable and no adjustment is required.

66. Customers and shareholders of Atmos Pipeline – Texas derive a benefit from the incentive compensation programs offered by the company and it is appropriate that the expenses for incentive compensation of direct employees be included in the cost of service calculation as they are just and reasonable expenses.

67. It is also appropriate that shareholder bear the burden of expenses for incentive compensation programs of the division that provide services to other divisions of Atmos Energy Corporation.

68. Atmos Pipeline – Texas has established that expenses for the pension account plan are just and reasonable.

69. The Supplemental Executive Benefit Plan is provided to employees that enter into a non-compete agreement and who have been designated by the Board of Directors. Shareholders and customers benefit from the program and it is reasonable that the cost of service calculation include expenses for the SEBP program expenses associated with direct employees of Atmos Pipeline – Texas.

70. Expenses associated with Cost Center 1905, Outside Director Retirement Costs, have been previously included in the calculation of the cost of service. These expenses are a necessary expense of publicly traded companies and it is just and reasonable to include those expenses in the cost of service calculation of the company.

Depreciation Expense

71. The company's proposed depreciation expenses, as reflected in the attached schedules are just and reasonable.

72. Atmos Pipeline – Texas correctly calculated the service life parameters for Accounts 352, 354, 367, 368, and 369.

73. The net salvage calculation included in the company's cost of service is just and reasonable for Account 352. The historical analysis is consistent with the functional data, experience of the company and industry experience for this account.

74. The net salvage calculation included in the company's cost of service is just and reasonable for Account 367. The analysis is consistent with the historical analysis, and industry experience for this account.

75. The expenses of Blueflame Insurance, an affiliate of Atmos Pipeline – Texas, are reasonable and necessary for the provision of natural gas service provided by the company.

76. The price to Atmos Pipeline – Texas by Blueflame is not higher than the price charged by Blueflame to its other affiliates or divisions or to a nonaffiliated person for insurance.

77. The Railroad Commission has previously found that the services provided by Blueflame were reasonable and necessary.

Revenues

78. Atmos Pipeline – Texas has established that the calculation of Other Revenues shown in the attached schedules is just and reasonable.

79. The company has included revenues for blending and treating fees.

80. It is reasonable to credit the revenue requirement for Other Revenue to determine the rates for Rate CGS and Rate PT classes.

81. It is reasonable to use a test year end, as adjusted, for Other Revenue.

82. It is reasonable to include retention gas sales in Other Revenue as a reduction to the revenue requirement.

83. It is reasonable in this instance to calculate retention gas sales value using an average over a four year period at a current market price.

84. It is reasonable to use a capital structure of 50.50% common equity and 49.50% long-term debt for Atmos Pipeline – Texas.

85. It is reasonable to use a cost of debt of 6.87% for Atmos Pipeline – Texas.

86. It is reasonable to use a proxy group of similar companies to Atmos Pipeline – Texas in the pipeline transmission business to determine a return on equity.

87. It is reasonable to use a constant growth Discounted Cash Flow Model for analysis to determine return on equity.

88. It is reasonable to use a quarterly growth Discounted Cash Flow Model for analysis to determine return on equity.

89. It is reasonable to use 30, 90, and 180-day ranges of average high and low share prices in the Discounted Cash Flow Model analysis.

90. It is reasonable to use a Capital Asset Pricing Model for analysis to determine return on equity.

91. It is reasonable to use a 90-day average of the 10-year Treasury Bond yield as a risk free rate.

92. It is reasonable that return on equity be set at 11.80%

93. An overall rate of return in this case of 9.361% is just and reasonable.

94. The evidence in this case established that a calculation of state gross margin tax based upon regulated operations and operations within the State of Texas is just and reasonable. Atmos Pipeline – Texas has established that its calculation of the state gross margin tax and is just and reasonable.

95. Atmos Pipeline – Texas has established that its calculation of federal income taxes as reflected in the attached schedules is just and reasonable.

96. Atmos Pipeline – Texas has established that the allocation of storage and transmission costs is just and reasonable and that those expenses are generated primarily by the city gate service customers.

97. The fixed cost allocation as proposed in this case is just and reasonable: The system is designed to satisfy the capacity requirements of the human needs customers during peak demand; peak demand determines the amount of transmission capacity and costs incurred by the company; and, no marginal or incremental cost of capacity are incurred when additional volumes of gas are transported.

98. Shifting 30% to 50% of the fixed costs to 62 individual customers is unreasonable and would serve only to subsidize the costs of providing service to the city gate service customers.

99. In GUD No. 9400, the Railroad Commission determined that the revenues from the non-regulated operations of Atmos Pipeline – Texas should be treated as a revenue credit.

100. Allocating costs to the Other Revenue customer class would treat those customers as if the customer were operating under a tariffed rate.

101. The proposal of Atmos Pipeline – Texas to treat the revenues from the non-regulate customers as a revenue credit is just and reasonable.

102. The straight fixed variable (SFV) rate design is a rate design that has been adopted by the majority of interstate natural gas pipelines in the United States and it sends proper price signals.

103. It is reasonable that the Railroad Commission of Texas have Atmos Pipeline – Texas create a Regulatory Asset as a result of Findings of Facts 64 and 65 in GUD No. 9869, Final Order Nunc Pro Tunc for Ad Valorem Tax and ADIT associated with working gas in storage.

104. It is reasonable to recover the Regulatory Asset through a surcharge on Rider CGS-Mid-Tex to only Atmos Mid-Tex through the Rider WGIS Working Gas Regulatory Asset Surcharge.

105. It is reasonable for the Commission to authorize the Rider WGIS Working Gas Regulatory Asset Surcharge.

106. It is reasonable that interest on the unrecovered balance accrue at the same rate of interest as the then-current deposit rate set by the Commission.

107. It is reasonable that the Regulatory Asset cease accruing upon implementation of the rates approved in GUD No. 10000.

108. It is reasonable that the surcharge be billed to Atmos Mid-Tex for twelve months.

Tariffs

109. The Railroad Commission of Texas has the authority approve adjustment mechanisms such as the Rider Rev because market forces control the revenues recovered from the non-regulated customers.

110. The Rider Rev is a reasonable mechanism to provide an annual adjustment to Rate CGS-Mid-Tex, and Rate CGS-other and Rate PT for 75% of the difference between the amount of Other Revenue determined in GUD No. 10000 and the amount of Other Revenue determined on an annual basis.

111. It is reasonable for the Rider Rev to be implemented on a three-year trial basis.

112. It is reasonable to review the results of Rider Rev at the end of three-years to determine if the Rider is achieving its stated goal and for the Commission to determine if the Rider Rev will be continued or eliminated.

113. It is reasonable that the Rider Rev specifically identify the allocation method to Rate CGS-Mid-Tex, Rate CGS-Other and Rate PT customer classes.

114. It is reasonable that the Rider Rev's review period be extended from 30-days to 60-days before its implementation.

115. It is reasonable that Atmos Pipeline – Texas provide notice to the customer of a rate increase or decrease that results from a Rider Rev adjustment.

116. It is reasonable that the Rider Rev incorporate language that will allow for Railroad Commission denial and subsequent appeal by Atmos Pipeline – Texas.

117. It is reasonable that the Rider Rev provide for Railroad Commission discovery during the review period with a five business day response from Atmos Pipeline – Texas.

118. It is reasonable to require an additional level of detail supporting the calculation of Rider Rev's Other Revenue and any adjustments to Other Revenue from the per book amount in its annual report.

119. It is reasonable to docket the annual review as a change in rates.

120. It is reasonable that if the change in rates under Rider Rev generates an increase in revenue of more than 2 ½%, then a hearing shall be held.

121. It is reasonable that the Rider Rev provide for cost recovery for the review by the Railroad Commission.

122. Atmos Pipeline – Texas has established that the cost of service without application of a revenue credit for revenues from non-regulated customers would be $226,763,998.

123. The rates necessary to recover $226,763,998 would be as follows:

   a. Rate CGS – Mid-Tex: Capacity Charge per MDQ, 6.2984 Mcf, Mid – Tex WGIS Charge, $0.8134 per Mcf, and a Usage Charge per MMBtu $0.0276.
   b. Rate CGS – CoServ: Capacity Charge per MDQ, 6.2984, and a Usage Charge per MMBtu, $0.0276.
   c. Rate CGS – City of Rising Star and West Texas Gas: Capacity Charge per MDQ, 6.2984 and a Usage Charge per MMBtu of $0.0276.
   d. Rate PT: Capacity Charge, 4.0732, Usage Charge $0.0163.

124. Atmos Pipeline – Texas has established that revenues from the non-regulated customers, Other Revenues are $83,723,391.63. Thus, the rates must be adjusted to allow recovery of $143,049,141.

125. The rates necessary to recover $141,882,173 are as follows:

   a. Rate CGS – Mid-Tex: Capacity Charge per MDQ, 3.6263 Mcf, Mid – Tex WGIS Charge, $0.8134 per Mcf, and a Usage Charge per MMBtu $0.0276.
   b. Rate CGS – CoServ: Capacity Charge per MDQ, 3.6263, and a Usage Charge per MMBtu, $0.0276.
   c. Rate CGS – City of Rising Star and West Texas Gas: Capacity Charge per MDQ, 3.6263 and a Usage Charge per MMBtu of $0.0276.
   d. Rate PT: Capacity Charge, 2.3061, Usage Charge $0.0163.

CONCLUSIONS OF LAW

1. Atmos Pipeline – Texas is a "Gas Utility" as defined in TEX. UTIL. CODE ANN. §101.003(7) (Vernon 2007 & Supp. 2010) and §121.001(2007) and is therefore subject to the jurisdiction of the Railroad Commission of Texas (Commission).

2. The Railroad Commission of Texas (Commission) has jurisdiction over Atmos Pipeline – Texas and its *Statement of Intent* under TEX. UTIL. CODE ANN. §§ 102.001, 103.022, 103.054, & 103.055, 104.001, and 104.201 (Vernon 2007).

3. Under TEX. UTIL. CODE ANN. §102.001 (Vernon 2007), the Commission has exclusive original jurisdiction over the rates and services of a gas utility that distributes natural gas in areas outside of a municipality and over the rates and services of a gas utility that transmits, transports, delivers, or sells natural gas to a gas utility that distributes the gas to the public.

4. This Statement of Intent was processed in accordance with the requirements of the Gas Utility Regulatory Act (GURA), and the Administrative Procedure Act, TEX. GOV'T CODE ANN. §§2001.001-2001.902 (Vernon 2008) (APA).

5. In accordance with the stated purpose of the Texas Utilities Code, Subtitle A, expressed under TEX. UTIL. CODE ANN. §101.002 (Vernon 2010), the Commission has assured that the rates, operations, and services established in this docket are just and reasonable to customers and to the utilities.

6. TEX. UTIL. CODE ANN. §104.107 (Vernon 2007) provides the Commission authority to suspend the operation of the schedule of proposed rates for 150 days from the date the schedule would otherwise go into effect.

7. The proposed rates constitute a major change as defined by TEX. UTIL. CODE ANN. §104.101 (Vernon 2007).

8. In accordance with TEX. UTIL. CODE §104.103 (Vernon 2007), 16 TEX. ADMIN. CODE ANN. §7.230 (2010), and 16 TEX. ADMIN. CODE ANN. § 7.235 (2010), adequate notice was properly provided.

9. In accordance with the provisions of TEX. UTIL. CODE ANN. §104.102 (Vernon 2007), 16 TEX. ADMIN. CODE ANN. §7.205 (2010), and 16 TEX. ADMIN. CODE §7.210 (2010), Atmos Pipeline - Texas filed its Statement of Intent to change rates.

10. Atmos Pipeline – Texas failed to meet its burden of proof in accordance with the provisions of TEX. UTIL. CODE ANN. §104.008 (Vernon 2007) on the elements of its requested rate increase identified in this order.

11. The revenue, rates, rate design, and service charges proposed by Atmos Pipeline - Texas are not found to be just and reasonable, not unreasonably preferential, prejudicial, or

discriminatory, and are not sufficient, equitable, and consistent in application to each class of consumer, as required by TEX. UTIL. CODE ANN. §104.003 (Vernon 2007).

12. The revenue, rates, rate design, and service charges proposed by Atmos Pipeline-Texas, as amended by the Commission and identified in the schedules attached to this order, are just and reasonable, are not unreasonably preferential, prejudicial, or discriminatory, and are sufficient, equitable, and consistent in application to each class of consumer, as required by TEX. UTIL. CODE ANN. §104.003 (Vernon 2007).

13. The overall revenues as established by the findings of fact and attached schedules are reasonable; fix an overall level of revenues for Atmos Pipeline – Texas that will permit the company a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public over and above its reasonable and necessary operating expenses, as required by TEX. UTIL. CODE ANN. § 104.051 (Vernon 2007); and otherwise comply with Chapter 104 of the Texas Utilities Code.

14. The revenue, rates, rate design, and service charges proposed will not yield to Atmos Pipeline – Texas more than a fair return on the adjusted value of the invested capital used and useful in rendering service to the public, as required by TEX. UTIL. CODE ANN. § 104.052 (Vernon 2007).

15. The rates established in this docket comport with the requirements of TEX. UTIL. CODE ANN. §104.053 (Vernon 2007) and are based upon the adjusted value of invested capital used and useful, where the adjusted value is a reasonable balance between the original cost, less depreciation, and current cost, less adjustment for present age and condition.

16. The rates established in this case comply with the affiliate transaction standard set out in TEX. UTIL. CODE ANN. § 104.055 (Vernon 2007). Namely, in establishing a gas utility's rates, the regulatory authority 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 an expense related to gas utility service expect 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. That finding must include (1) a specific finding of reasonableness and necessity to each 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.

17. In accordance with TEX. UTIL. CODE ANN. §104.054 (Vernon 2007) and Tex. Admin. Code §7.5252, book depreciation and amortization was calculated on a straight line basis over the useful life expectancy of Atmos Pipeline – Texas's property and facilities.

18. In this proceeding, Atmos Pipeline - Texas has the burden of proof under TEX. UTIL. CODE ANN. §104.008 (Vernon 2007) to show that the proposed rate changes are just and reasonable.

19. TEX. UTIL. CODE ANN. § 104.301, allows a utility to make an interim rate adjustment and requires that the utility that files an interim rate adjustment must also file a rate case under Subchapter C of the Gas Utility Regulatory Act (Statement of Intent Proceeding) at the fifth year anniversary of the effective date of the first interim rate adjustment.

    a. There is nothing in Tex. Util. Code Ann. § 104.301 that precludes a utility from voluntarily removing certain expenditures in its interim rate adjustments and then including those expenditures in the subsequent Statement of Intent Proceeding.

    b. All interim rate adjustments are subject to refund in the subsequent Statement of Intent Proceeding.

    c. All interim rate adjustments of Atmos Pipeline – Texas were reviewed in this proceeding and except for the items set out in Finding of Fact Nos. 17 – 40 above were found to be just and reasonable.

20. Rate case expenses for GUD No. 10000 will be considered by the Commission in accordance with TEX. UTIL. CODE ANN. §104.008 (Vernon 2010), and 16 Tex. Admin. Code §7.5530 (2010), in a separate proceeding.

21. Atmos Pipeline – Texas is required by 16 Tex. Admin. Code §7.315 (2008) to file electronic tariffs incorporating rates consistent with this Order within thirty days of the date of this Order.

22. Atmos Pipeline – Texas is required by 16 Tex. Admin. Code § 7.310 to utilize the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA) prescribed for natural gas companies.

23. The Railroad Commission of Texas has the authority under TEX. UTIL. CODE §§ 102.001, 102.104, 104.001, 121.151 and the Federal Energy Regulatory Commission's Uniform System of Accounts, Definitions, No. 31, Regulatory Asset to authorize and approve a Regulatory Asset.

IT IS THEREFORE ORDERED that Atmos Pipeline – Texas's proposed schedule of rates is hereby **DENIED**.

IT IS FURTHER ORDERED that the rates, rate design, and service charges established in the findings of fact and conclusions of law and shown on the attached Schedules for Atmos Pipeline – Texas are **APPROVED**.

IT IS FURTHER ORDERED that a refund in the amount of $1,134,253, shall be made as set out in the attached schedule, Ad Valorem Tax GRIP Refund by Customer Class Plus Interest.

IT IS FURTHER ORDERED that in future rate proceedings Atmos Pipeline – Texas shall include detailed receipts for all meal and lodging expenses and that there shall be a rebuttable presumption that meal expenses $25 and under and lodging expenses $150 and under are just and reasonable and that Atmos Pipeline – Texas must establish that any expenses in excess of $25 for meals and $150 for lodging are just and reasonable, exclusive of taxes.

IT IS FURTHER ORDERED that, in accordance with 16 Tex. Admin. Code §7.315, within 30 days of the date this Order is signed, Atmos Pipeline – Texas shall file tariffs with the Gas Services Division. The tariffs shall incorporate rates, rate design, and service charges consistent with this Order, as stated in the findings of fact and conclusions of law and shown on the attached Schedules.

IT IS FURTHER ORDERED that all proposed findings of fact and conclusions of law not specifically adopted in this Order are hereby **DENIED**. **IT IS ALSO ORDERED** that all pending motions and requests for relief not previously granted or granted herein are hereby **DENIED**.

This Order will not be final and effective until 20 days after a party is notified of the Commission's order. A party is presumed to have been notified of the Commission's order three days after the date on which the notice is actually mailed. If a timely motion for rehearing is filed by any party at interest, this order shall not become final and effective until such motion is overruled, or if such motion is granted, this order shall be subject to further action by the Commission. Pursuant to TEX. GOV'T CODE §2001.146(e), the time allotted for Commission action on a motion for rehearing in this case prior to its being overruled by operation of law, is hereby extended until 90 days from the date the order is served on the parties.

All requested findings of fact and conclusions of law which are not expressly adopted herein are denied. All pending motions and requests for relief not previously granted or granted herein are denied.

SIGNED this 18th day of April, 2011.

RAILROAD COMMISSION OF TEXAS

Elizabeth Ames Jones

CHAIRMAN ELIZABETH AMES JONES

David Porter

DAVID PORTER COMMISSIONER

ATTEST:

Kathy Way

SECRETARY

HOUSE RESEARCH ORGANIZATION bill analysis 4/11/2019

(2nd reading)
HB 1767
Murphy, et al.

SUBJECT: Considering total employee compensation when setting gas utility rates

COMMITTEE: State Affairs — favorable, without amendment

VOTE: 11 ayes — Phelan, Deshotel, Harless, Holland, Hunter, P. King, Parker, Raymond, E. Rodriguez, Smithee, Springer

0 nays

2 absent — Hernandez, Guerra

WITNESSES: For — Jason Ryan, CenterPoint Energy; Mark Bender, Texas Gas Service; (*Registered, but did not testify*: Julia Rathgeber, Association of Electric Companies of Texas; Chance Sampson, Entergy Texas, Inc.; Lee Parsley, Texans for Lawsuit Reform; Thure Cannon, Texas Pipeline Association)

Against — Thomas Brocato, Steering Committee of Cities Served by Oncor, Steering Committee of Cities Served by Atmos, Texas Coalition for Affordable Power; (*Registered, but did not testify*: Alfred Herrera, Counsel for Cities Advocating Reasonable Deregulation, Texas Coast Utilities Coalition of Cities, Alliances of CenterPoint Municipalities, Atmos Texas Municipalities; Shanna Igo, Texas Municipal League)

On — (*Registered, but did not testify*: Mark Evarts, Railroad Commission of Texas)

DIGEST: HB 1767 would require the Railroad Commission, when establishing a gas utility's rates, to presume that employee compensation and benefits expenses were reasonable and necessary if the expenses were consistent with recent market compensation studies.

"Employee compensation and benefits" would include base salaries, wages, incentive compensation, and benefits. The term would not include pension and other postemployment benefits.

HB 1767 would apply only to a proceeding for the establishment of rates for which the regulatory authority had not issued a final order or decision before the bill's effective date.

The bill would take immediate effect if finally passed by a two-thirds record vote of the membership of each house. Otherwise, it would take effect September 1, 2019.

SUPPORTERS SAY:

HB 1767 would require the total compensation of gas utility employees, based on market studies, to be considered by the Railroad Commission as a reasonable and necessary expense of a utility. The bill would make rate regulation more predictable, more efficient, and less litigious.

The calculation of total compensation is dependent on market studies, which are used to determine the total of base and contingency pay for employees that was appropriate for the utility to remain competitive in the market.

Allowing gas utilities to recover funds for the total compensation of their employees would be appropriate, as these expenses are necessary for them to operate in a safe and effective manner and to retain employees. The uniform consideration of these expenses also would help reduce litigation on rate regulation, ultimately saving ratepayers money.

The bill would use the typical standard for determining compensation through market studies, which gas utilities already use, and simply codify a process already in place. Since contingency pay still would depend on employee performance, this bill would not remove employee incentives.

OPPONENTS SAY:

HB 1767 would allow a gas utility to inappropriately include bonus payments for employees in rates with little or no oversight.

Because the bill would automatically deem compensation "reasonable and necessary" as long as a utility produced a study supporting the total compensation rate, there would be little to no review of what the compensation should be. These costs would be passed on to ratepayers, who should not be responsible for covering them. Utility shareholders, not ratepayers, should bear the cost of this additional employee compensation, in keeping with standard practices. Allowing bonus payments in the rate setting process also would remove incentives for employees.

The bill is vague because it would not provide a definition of what constituted consistency with market studies or how recent the studies should be. Because utilities often pay for these compensation studies themselves, the process would lack independent oversight.

WORKPAPERS

TO

DIRECT TESTIMONY

OF

STACEY L. MCTAGGART

Workpapers to the Direct Testimony of Stacey L. McTaggart are voluminous and are being provided in electronic format.

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.

Oregon Public Utility Commission Pension Survey
"Pension Treatment in Rate Making Survey"
Summary Report

Thursday, March 28, 2013

This document is a compilation of the Public Utility Commission of Oregon (OPUC) survey, "Pension Treatment in Rate Making." The survey was sent to and responded by the fifty state utility commissions, The District of Columbia, and the City of New Orleans. The OPUC greatly appreciates the time and effort taken by the commission to respond to the survey.

The answers provide below will help to inform all of the utility commissions about the types of regulatory recovery utilities in the United States are receiving from their utility regulatory authorities. It also identifies by the commission answers where in the United States that these regulatory methodologies are being applied.

Question - 1

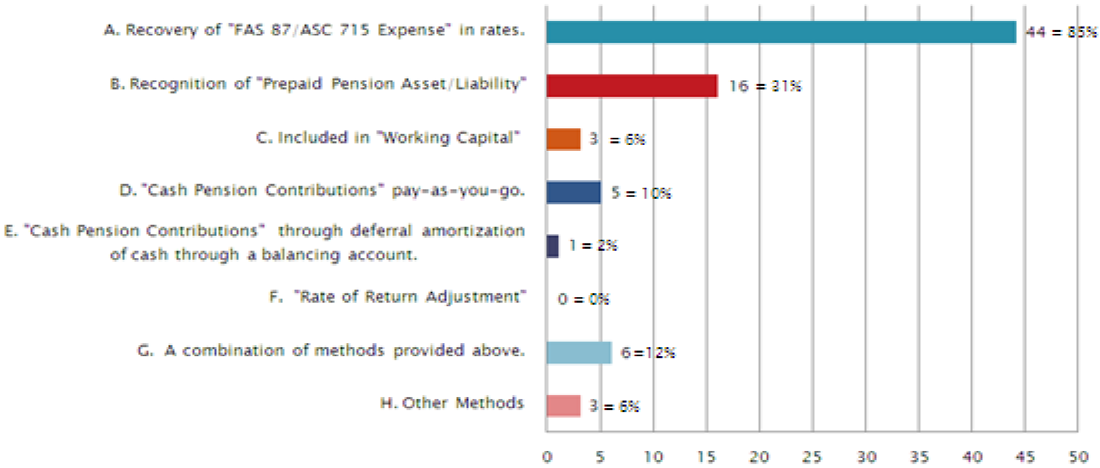
Please pick which method, listed below from A through H, that your commission used as its basis for deciding the level of recovery that companies receive in rates for cash contributions and pension expenses related to the funding and operation of...

(Response Rate: 100% (N=52) Question Type: Choose many)

A. Recovery of "FAS 87/ASC 715 Expense" in rates (Defined as the Net Periodic Pension (Benefit)/Cost)	**44**
B. Recognition of "Prepaid Pension Asset/Liability" (Delta of defined benefit contribution minus FAS 87/ASC 715 expense; recognized in rates through allowing a return on amount invested in asset)	**16**
C. Included in "Working Capital" (As an adjustment to the balance of working capital)	**3**
D. "Cash Pension Contributions" pay-as-you-go (Use of cash contributions instead of the accrual based FAS 87/ASC 715 by including cash contributions during the test-year in the revenue requirement)	**5**
E. "Cash Pension Contributions" (deferral and amortization of cash contributions through a balancing account)	**1**
F. "Rate of Return Adjustment" (An adjustment to the allowed rate-of-return)	**0**
G. "Combination of Methods" of the above	**6**
H. "Other Method(s)"	**3**
Total Responses	**78**

Note: Will not add up to 52 (number of participating commissions) because more than one of the above statements could be chosen as applicable to explain commission orders related to pension expenses.

Question – 1 (Table)



Question - 1 (Text Field - 1)

If you selected multiple methods, please provide a brief explanation of how the methods are used

Response Rate: 35% (N=18) Question Type: Paragraph

South Carolina Public Service Commission - "A rider comprised of the difference between the FAS-87 expense in rates and the FAS-87 project subject to true up."

Pennsylvania Public Utility Commission – "One company that I know of uses FAS 87 accrual method (PPL). Generally speaking, for all others, we review the company's actuarial study and verify whether claim falls between ERISA and IRC amounts."

Oklahoma Corporation Commission – "A combination of A and B."

Public Service Commission of West Virginia - Virginia Historically the WV PSC has recognized pensions based on the cash contribution method (ERISA) and continues to utilize that method for most private utilities. Recently in Mountaineer Gas (case #11-1627-E-42T), the Commission recognized pension expense at the level of the FAS 87 accured expense, but only on condition proposed by Mountaineer that they will fund the pension plan annually at the FAS 87 expense level (even if the FAS 87 level exceeds the ERISA cash funding requirement). In addition, the Commission has allowed pension recovery using the FAS 87 accrual level for American Water Works Service Company charges to West Virginia-American because the majority of the 21 states regulating AWW subsidiaries recognize FAS 87 for pension recovery."

Kentucky Public Service Commission – "KYPSC does not require a specific recovery method. While ash "pay-as-you-go" was used historically, in some recent cases have transitioned to FAS 87/ASC 715 expense."

New Mexico Public Regulation Commission – "The NMPRC historically has allowed the FAS 87 Expense to be included as a recoverable operating expense. In Case 07-

00319-UT, however, the NMPRC also allowed the applicant utility, Southwestern Public Service Company, to include a prepaid pension asset because the utility demonstrated that the pre-paid pension asset caused a negative pension expense. The fact that the prepayment resulted from a high rate of return on the pension fund, as opposed to the utility having made discretionary excess contributions to the fund, appears to have caused the NMPRC to be more favorably disposed to allow inclusion of the prepaid pension asset in rate base. This is the most recent litigated rate case that addressed this issue."

Public Utility Commission of Utah –"In Utah there is only one investor owned utility. Older employees are grandfathered into a defined benefit plan along with the union employees (FASB 87). Effective June 1, 2007, the Company shifted its benefit determination for the non-union workforce to a cash balance plan/401K approach. For non-union employees, all vested benefits under the current final average pay approach were frozen as of May 31, 2007 and will be provided to employees at the time of retirement. Effective June 1, 2007, the Company established an account for each employee that will grow based on credits of 6.5 percent of annual pay (base plus incentive) plus 4.0 percent of pay in excess of the Social Security taxable wage base ($97,500 in 2007). In addition, on an annual basis each account will receive an interest credit based on the account balance and the annual credit rate. A transition benefit was provided for employees who are age 40 or older on May 31, 2007. Employees falling in this category will receive additional pay credits for five years (ending in 2012), structured as follows: Year 1-3 = 4.0 percent Year 4 = 2.5 percent Year 5 = 1.5 percent All new hires eligible to participate in the pension plan after June 30, 2006 will receive a pay credit rate of 5.0 percent The Company no longer offers defined benefit plan to those not grandfathered into old plan."

District of Columbia Public Service Commission –"The Commission allows the electric and natural gas utilities to use the ASC 715 method to account for Pension by reflecting in the utility's operating expense the actuarily determined net periodic Pension cost or benefit. However as described in a later survey response, the Commission has allowed the Electric utility to include in rate base the electric utility's prepaid pension asset balance.

Maine Public Utilities Commission – "In the Stipulation approved in Docket No. 2007-215 (paragraph 19), it was agreed that the utility would amortize a regulatory liability representing the actuarial gains not yet recognized in pension expense amounts over 5 years. The liability was required due to the merger of the utility and a new parent."

California Public Utilities Commission – "The answer above is to the best of my knowledge."

New York State Public Service Commission – "NYPSC allows ASC 715 expense with reconciliation so to recover actual expense. Carrying charges accrued to ratepayers on balance of "internal reserve" where pension costs provided in rates (expense plus amounts charged to CWIP) are greater than contributions to fund."

Vermont Public Service Department - "In Vermont, the expense under FAS 87 is recoverable in rates. Additionally, the net asset or liability balance is included in the rate base."

Illinois Commerce Commission - Pension expense is based on FAS 87 Expense. In addition, a return on the Pension Asset recorded on the utilities books has been approved for Commonwealth Edison in rate cases since Docket No. 05-0597.

Massachusetts Department of Public Utilities - We use both A and D.

New Jersey Board of Public Utility - Recovery of FAS 87 expense as well as adding the prepaid pension balance to cash working capital study to get a return on that balance.

Minnesota Public Utilities Commission - A. on a case by case basis has allowed recovery as a test year cost either the FAS 87 cost or an average of several years of FAS 87 cost. B.In one instance the Commission has allowed the excess of the company's contributions over the amounts recovered in rate to be included in rate base as part of a settlement.

Virginia State Corporation Commission - The expensed amount of the NPBC is included in O&M, the accrued Pension Asset/Liability is usually recognized as a working capital adjustment in a lead/lag study.

Public Utility Commission of Texas - Pension expense determined in rate case by FAS 87. Each year thereafter, reserve account is debited or credited for difference between amount included in rates and that year's FAS 87 pension expense amount. Next rate case any deficit or surplus in the reserve account is amortized over a reasonable time with the unamortized balance earning a return.

Question - 1 (Text Field - 2)

You answered H. "Other Methods, to question 1," please provide a brief explanation of the method used.

Response Rate: 6% (N=3) Question Type: Paragraph

Tennessee Regulatory Authority - Latest minimum funding level in latest actuarial report allowed as pension expense in rates.
Missouri Public Service Commission - Prior rate recognition of FAS 87 pension credits is also amortized to cost of service in current cases. For most Missouri utilities, the amount of the required pension case contributions is set equal to the utilities' FAS 87/ASC 715 annual expenses.

Washington Utilities and Transportation Commission - We also use a four-year average of cash contributions to the pension asset. Different utilities may get different treatment.

Question - 2

Has your commission allowed the inclusion in a company's "rate base" any portion of a company's pension expenditures that are excess contributions over FAS 87/ASC 715 based expenses or result in "pre-paid pension expense" in a company's "rate base" used for setting rates, or are deferred pension costs allowed a carrying charge?

(Response Rate: 100% (N=52) Question Type: Choose one)

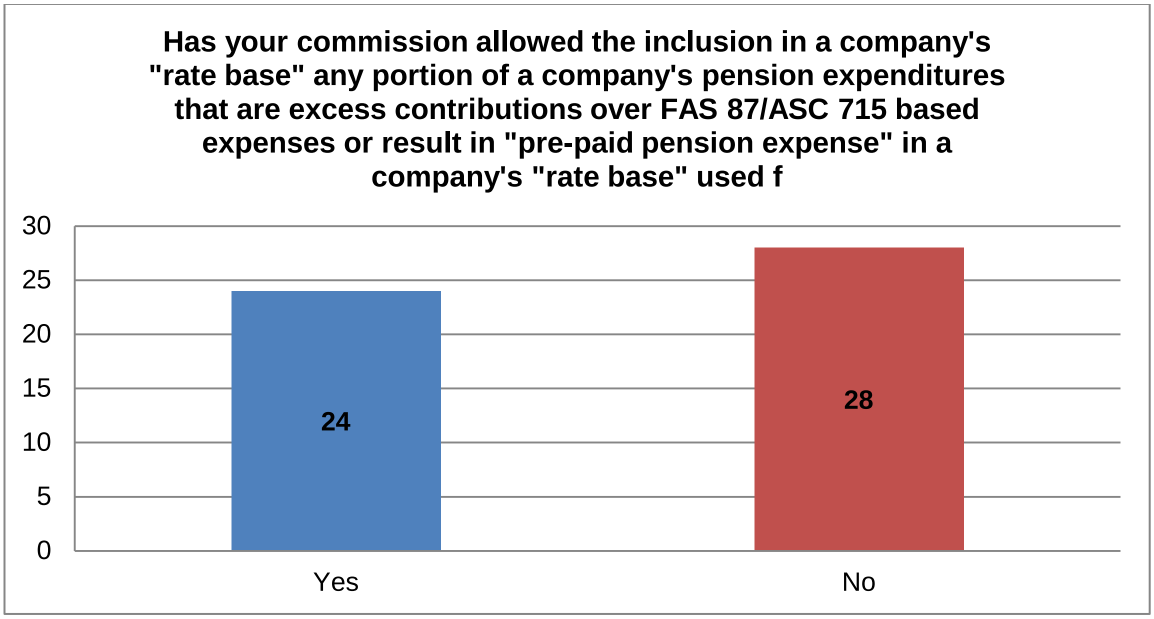
Yes - 24

Colorado Public Utility Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Florida Public Service Commission
Hawaii Public Utility Commission
Illinois Commerce Commission
Louisiana Public Service Commission
Michigan Public Service Commission
Minnesota Public Utilities Commission
Mississippi Public Service Commission
Missouri Public Service Commission
New Hampshire Public Utilities Commission
New Jersey Board of Public Utility
New Mexico Public Regulation Commission
New Orleans City Council Utilities Regulatory Office
New York State Public Service Commission
North Carolina Utilities Commission
Oklahoma Corporation Commission
Public Utilities Commission of Ohio
Public Utility Commission of Texas
Rhode Island Public Utilities Commission
South Carolina Public Service Commission
Vermont Public Service Department
Virginia State Corporation Commission

No – 28

Total Responses - 52

Table – Question – 2



Question - 2 (Text Field - 1):

Has your commission allowed the inclusion in a company's "rate base" any portion of a company's pension expenditures that are excess contributions over FAS 87/ASC 715 based expenses or result in "pre-paid pension expense" in a company's "rate base" used for setting rates, or are deferred pension costs allowed a carrying charge?

***South Carolina Public Service Commission* – “**The difference between the FAS-87 expense in rates and the projected FAS-87 expense is amortized over 30 years with the unamortized balance in rate base that earns a return at the allowed ROR.”

***Louisiana Public Service Commission* -** Allowed as a pre-payment as a rate base

***Oklahoma Corporation Commission* –** “Prepaid pension assets are generally included in rate base. However, this is a contentious item amongst the parties to the cause. Also the rate of return/cost of debt allowed is also a contentious item.”

***New Hampshire Public Utilities Commission* –** “Prepaid expenses.”

***Missouri Public Service Commission* -** ”Any additional pension funding by the utilities above the FAS 87/ASC 715 level associated with minimum ERISA or Pension Protection Act of 2006 requirements is generally allowed to be deferred on the utilities’ balance sheets , and then placed in rate base in subsequent general rate proceedings.”

***New Mexico Public Regulation Commission* -** “As explained above, the NMPRC has allowed a pre-paid pension asset to be included in rate base, earning the utility's allowed weighted average cost of capital, if the utility demonstrated satisfactorily that the pre-paid pension asset caused a negative pension expense."

New Orleans City Council Utilities Regulatory Office – "While "pre-paid pension expense" has been allowed, the level of contributions is closely monitored to ensure the Company is not over funding pension plans."

Connecticut Department of Public Utility Control – "This is done on a case by case basis depending on the circumstances of each case."

District of Columbia Public Service Commission – "In FC 1053 (See DC PSC Order No. 14712 issued on January 30, 2008). Pepco was allowed to include $23.3 million in its rate base for prepaid asset/OPEB liability net of taxes. In that case, the Commission found that inclusion of Prepaid Pension Asset/OPEB Liability in the rate base is consistent with Commission precedent. In an earlier case concerning another utility (BA-DC), the Commission found that BA-DC was required to continue its policy of placing an amount equal to the SFAS accrual into an external funding mechanism to the extent that tax advantaged vehicles exist, with any accruals in excess of that amount applied as a reduction to rate base. In a subsequent case involving PEPCO, the Commission similarly found that "as in the BA-DC case, it is appropriate that PEPCO account for any amounts not externally funded ... as a reduction to the rate base." The Commission found that investor-supplied cash contributions have resulted in an asset from which PEPCO's customers receive a tangible benefit in the form of reduced pension expenses. Therefore, investors are entitled to earn a return on the capital they provided. If the Prepaid Pension Asset is included in rate base, the related OPEB Liability should also be included as a reduction. Both the asset and the liabilitv result from the existence of a differential between theCompany's obligation regarding future benefits owed to current employees and the level of those benefits the Company funds currently."

Rhode Island Public Utilities Commission – "The pension contributions in excess of the accrued liability are allowed a return in the pension reconciliation mechanism."

North Carolina Utilities Commission – "Excess contributions, typically, would beincluded in rate base."

New York State Public Service Commission – "With authorization of the NYPSC a NY utility can accrue carrying charges at its allowed rate of return where contributions to date are in excess of pension expense allowed in rates and charged to CWIP."

Vermont Public Service Department - Yes, when there is/was an unfunded pension obligation.

Illinois Commerce Commission - While the "pre-paid pension expense" has not been allowed for recovery in "rate base", utilities have been allowed to recovery a return on what it has recorded as a "pension asset" at the weighted average cost of capital in its operating statement.

Colorado Public Utility Commission - The prepaid pension asset is also included.

New Jersey Board of Public Utility - If the utility's pension is prepaid, the 13 month average to the cash working capital requirement rolls into rate base.

Minnesota Public Utilities Commission - In one instance as part of a rate case settlement this was allowed.

Hawaii Public Utility Commission - We have a pension and OPEB tracking mechanism that is designed to provide for the recovery of pension and OPEB costs over time. By preventing the over or under recovery of costs, by establishing a prepaid pension asset or liability. The pension tracking mechanism ensures that over time the pension costs recovered through rates are based on the actuarially calculated NPPC as reported for financial reporting purposes and ensures that all amounts contributed to the pension trust fund are in amounts at least equal to actual NPPC and recoverable through rates. Thus, the test year NPPC is estimated and incorporated into rates in each rate case. Once new rates are effective and until rates are changed in a subsequent rate case, taht amount of NPPC in rates and the actual NPPC is separately tracked. The difference between the NPPC in rates and athe actuarially calculated NPPC for the year is charged/credited to a regulatory asset/liability. this unamortized regulatory asset/liability is included in rate base. When new raes are established in a rate case, the regulatory asset/liability is amortized over a five year period. The total test year pension costs is the test year NPPC in rtes plus or minus the amortization of the regulatory asset/liability. Also, the pension tracking mechanism allows the utilty to reverse the pension AOCI charge to equity and credate a regulatory asset for financial statement purposes.

Virginia State Corporation Commission - The expensed amount of the NPBC is included in O&M. The accrued Pension Asset/Liability is usually recognized as a working capital adjustment in a lead/lag study.

Public Utility Commission of Texas - Several years ago AEP companies made excess contributions to pension funds and were allowed to include these amounts in rate base. See PUCT Docket No. 33309

Michigan Public Service Commission - Our Commission uses the balance sheet method for working capital and all assets and liabilities associated with pension are included in working capital.

Question - 3

Has your commission applied an adjustment to a company's discount rate used to calculate its FAS 87/ASC 715 accrual based expenses used in setting rates?

Response Rate: 100% (N=52) Question Type: Choose one

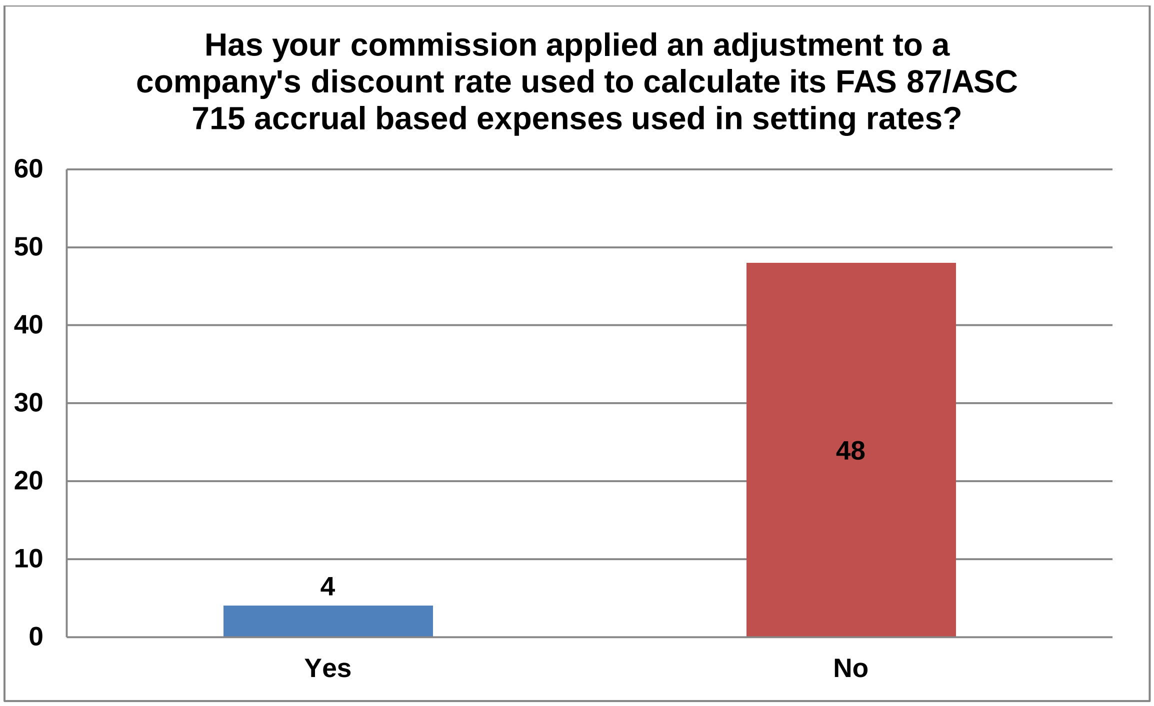
Yes – 4

Idaho Public Utilities Commission
Public Service Commission of Wisconsin
Connecticut Department of Public Utility Control
New Hampshire Public Utilities Commission

No – 48

Total Responses – 52

Table – Question - 3



Question - 3 (Text Field - 1):

Has your commission applied an adjustment to a company's discount rate used to calculate its FAS 87/ASC 715 accrual based expenses used in setting rates?

Idaho Public Utilities Commission - In 2003, the Utility decreased its discount rate prior to a test year for a general rate case from 8.5% to 8%, although the returns for the previous 15 years averaged 13%. The Commission found that the utility's change in discount rate was unwarranted. However, the issue was mute because the Utility had not been funding contributions for over 10 years, so the Commission didn't allow any recovery in rates

Public Service Commission of Wisconsin - No adjustments in recent years other than to include updated information from actuarial studies completed during Commission staff's audit of the forward looking test year.

Connecticut Department of Public Utility Control - The PURA adjusts the discount rate based on market conditions projected for the future.

New Hampshire Public Utilities Commission - It depends on company's filing and its actuarial study

Question - 4

Has the commission applied an adjustment to a Company's "rate-of-return" used to calculate a Company's FAS 87/ASC 715 based pension plan portfolio value used in setting rates?

Response Rate: 100% (N=52) Question Type: Choose one

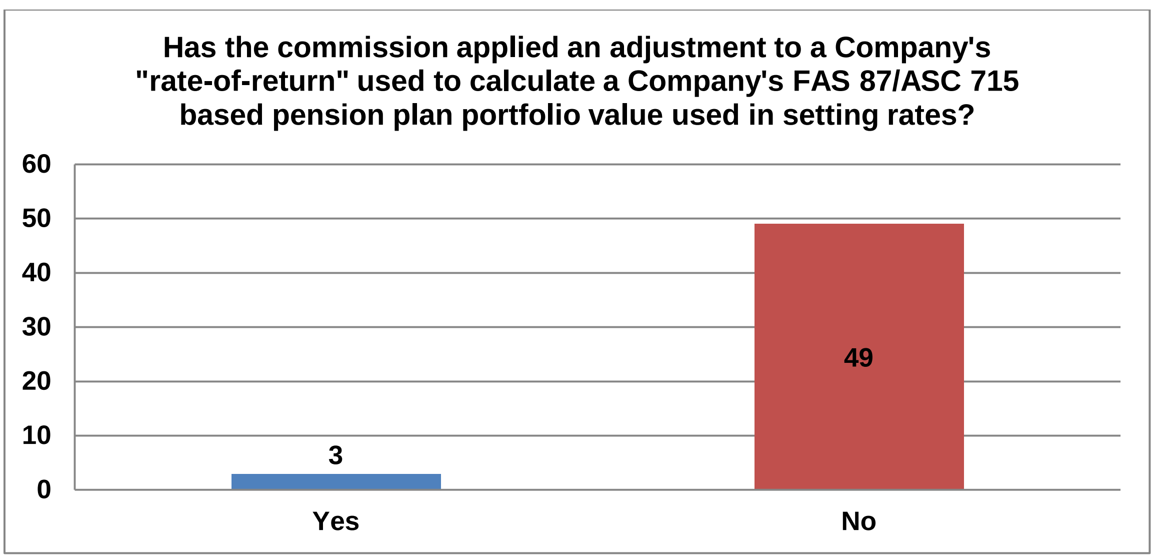
Yes – 3

Connecticut Department of Public Utility Control
New Hampshire Public Utilities Commission
Public Service Commission of Wisconsin

No – 49

Total Responses – 52

Table – Question - 4



Question - 4 (Text Field – 1)

Has the commission applied an adjustment to a Company's "rate-of-return" used to calculate a Company's FAS 87/ASC 715 based pension plan portfolio value used in setting rates?

Response Rate: 6% (N=3) Question Type: Paragraph

Connecticut Department of Public Utility Control - The PURA adjusts the rate of return on pension assets based on market conditions projected for the future.

New Hampshire Public Utilities Commission - ask for explanation on rate used, company may agree to change

Public Service Commission of Wisconsin – No adjustments in recent years other than to include updated information from actuarial studies completed during Commission staff's audit of the forward looking test year.

Question - 5

Has your commission recently performed, or is it currently performing, an investigation into pension related costs? If so, please select "Yes" and provide the docket number in the box below.

Response Rate: 98% (N=51) Question Type: Choose one

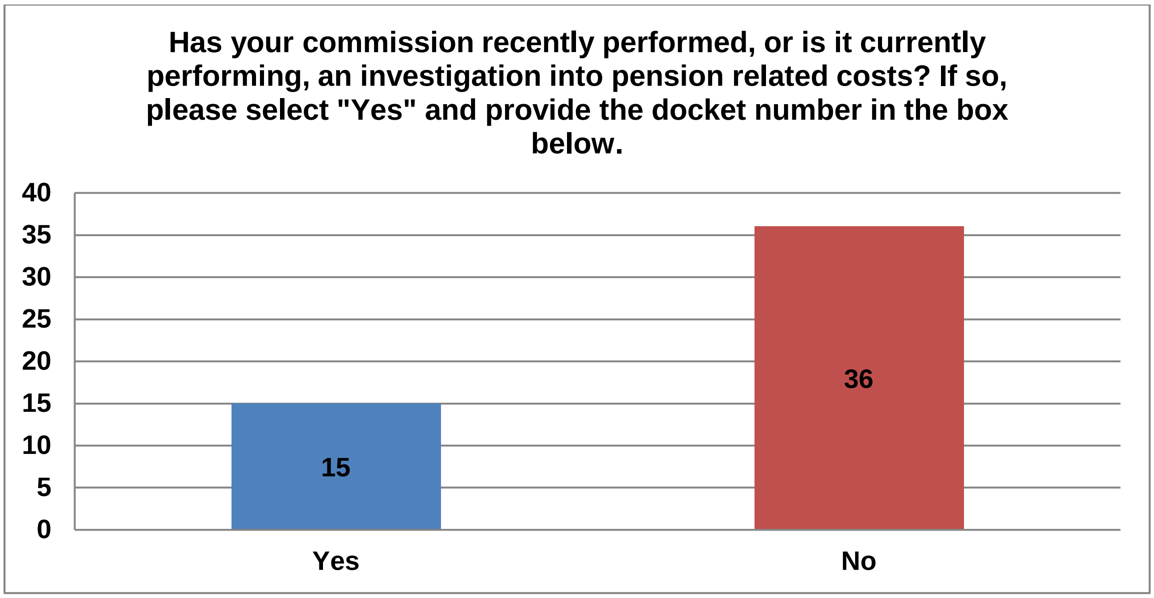
Yes – 15

California Public Utilities Commission
Colorado Public Utility Commission
Delaware Public Service Commission
District of Columbia Public Service Commission
Hawaii Public Utility Commission
Idaho Public Utilities Commission
Kansas Corporation Commission
Michigan Public Service Commission
New Mexico Public Regulation Commission
New Orleans City Council Utilities Regulatory Office
New York State Public Service Commission
North Carolina Utilities Commission
Oregon Public Utility Commission
Rhode Island Public Utilities Commission
South Carolina Public Service Commission
Washington Utilities and Transportation Commission

No – 36

Total Responses – 51
Note: South Carolina Public Service Commission chose not to answer yes or no.

Table – Question- 5



Question - 6

Has your commission ever considered or been presented with the issue of whether a utility should be allowed to earn a return on amounts that it has invested into its pension plan that are in excess of amounts collected in rates?

Yes -17

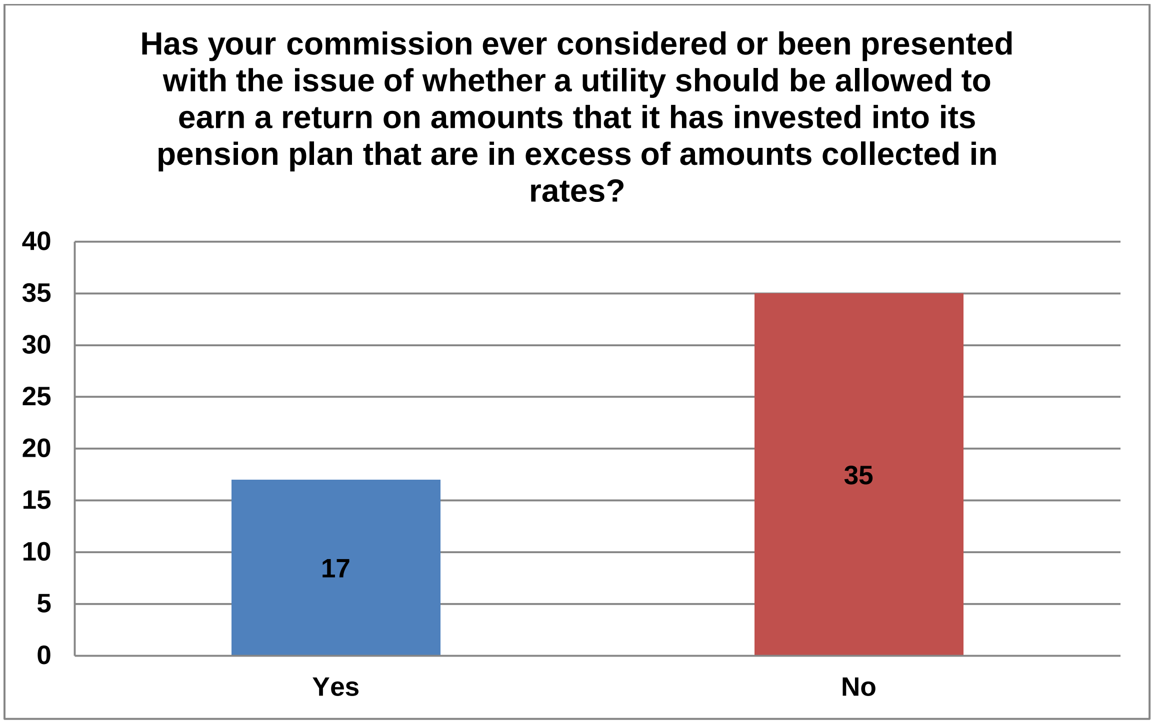
District of Columbia Public Service Commission
Hawaii Public Utility Commission
Idaho Public Utilities Commission
Illinois Commerce Commission
Indiana Utility Regulatory Commission
Kansas Corporation Commission
Louisiana Public Service Commission
Minnesota Public Utilities Commission
New Mexico Public Regulation Commission
New York State Public Service Commission
Oklahoma Corporation Commission
Oregon Public Utility Commission
Public Service Commission of West Virginia

Public Utilities Commission of Ohio
Public Utility Commission of Texas
Rhode Island Public Utilities Commission
South Carolina Public Service Commission

No – 35

Total Responses – 52

Table – Question – 6



Question – 6 (order numbers with descriptions)

If your commission's order reflecting its decision on this issue is not noted above, please provide the order number and a brief description in the box provided below.

California Public Utilities Commission - The answer to the above question is to the best of my knowledge. Would require extensive research to get a definitive "yes" or "no".

District of Columbia Public Service Commission - In Formal Case No. 1093, Washington Gas Light asks that it be allowed to include in rates the under collected balance of its Pension expenses, which it was allowed to defer and track since the last rate case. The outstanding balance earns a return using a Commission-approved rate. This balance is in excess of the amount already included in rate. This issue is still under consideration in Formal Case No. 1093. However, since this tracker mechanism has been in place for several years, it has been addressed in Formal Case No. 1016 (DC PSC Order No. 12986, issued on November 10, 2003).

Hawaii Public Utility Commission - Pension tracking mechanism approved in Docket No. 2005-0315, filed October 28, 2010, HELCO 2006 TY rate case.

Illinois Commerce Commission - 09-0263, 07-0566

Indiana Utility Regulatory Commission - Case is pending Cause No. 44075

Kansas Corporation Commission – 04-KCPE-1025-GIE The Commission allowed Kansas City Power and Light to earn a return on amounts in excess collected in rates. In the 10-KCPE-415-RTS rate case the Commission changed its mind and disallowed the utility the ability to earn a return on excess amounts.

Louisiana Public Service Commission - U-20925-2004 Evaluation is made during annual review of the formula rate plan.

Minnesota Public Utilities Commission - Minnesota Power has made such a request outside a rate case in Docket E-015/M-11-1264. An order has not been issued at this time.

New Mexico Public Regulation Commission - This issue has been addressed in the cases noted below.

New York State Public Service Commission - Case 07-G-0141, order issued 12/21/2007

Pennsylvania Public Utility Commission - n/a

Public Service Commission of West Virginia - Not in a formal case filing, but the Commission was presented such a proposal in the form of a Request For Accounting Change, where the West-Virginia American requested authorization to defer pension expense in excess of the level on which existing rates were determined. They requested authorization to defer under FAS 71. This case was never officially docketed and subsequently became moot when they filed a subsequent general rate increase petition.

Public Utilities Commission of Ohio - See Columbus Southern Power 11-351--EL-AIR (see page 7 of report)

South Dakota Public Utilities Commission - Not aware of any order addressing this issue specifically.

Pension Relevant Docket Numbers:

California Public Utilities Commission - SDG&E/SoCalGas A.10-012-005/-006 available on CPUC website.

Delaware Public Service Commission – In the matter of the petition of Delmarva Power and Light Company for authorization to defer certain charges to the Company's financial statements resulting from the impact of recent economic developments on pension costs (filed May 1, 2009 – Docket 09-182.

Kansas Corporation Commission - 07-GIMX-1041-GIV

Michigan Public Service Commission - We do audit pension expense with each case, but typically adopt FAS 87 expense.

New Mexico Public Regulation Commission - Although the NMPRC has not recently performed, nor is currently performing an investigation specifically into pension related costs, the pension related costs of Southwestern Public Service Company, along with all other costs, will be examined in pending Case No. 12-00350-UT (Southwestern Public Service Company general rate case).

New Orleans City Council Utilities Regulatory Office - CNO Docket No. UD-08-03

New York State Public Service Commission - Case 07-W-0463, Case 10-M-0263, Case 11-W-0070

North Carolina Utilities Commission - Docket No. E-100, Sub 112 Docket No. G-9, Sub 545 Docket No. G-5, Sub 485

Oregon Public Utility Commission - UG 221 Northwest Natural Gas (General Rate Case) UM 1633 - Combined UM 1619 - 1630 Northwest Natural Gas UM 1623 Portland General Electric UM 1642 Pacific Power and Light

Pennsylvania Public Utility Commission - None to my knowledge.

Public Service Commission of Wisconsin - 05-UI-104, Investigation on the Commission's Own Motion into the Proper Ratemaking Treatment for Post Retirement Benefits Other Than Pensions, Order issued 10/30/1992; 5-GF-168, Joint Application of Wisconsin Public Service Corporation, Madison Gas and Electric Company, Wisconsin Electric Power Company, Wisconsin Gas LLC, and Wisconsin Power and Light Company Regarding Implementation of SFAS 158, accounting letter dated 10/15/2007 5-GF-168 http://sql01/apps35/ERF_view/viewdoc.aspx?docid=83943

Rhode Island Public Utilities Commission - Docket No. 4323

South Carolina Public Service Commission - 2012-218-E 2011-271-E

Washington Utilities and Transportation Commission - PacifiCorp Docket UE-130043

Pension Related Order Numbers:

"Please provide commission order number(s) that correspond to the most recent general rate cases or other proceeding, in which pension funding was evaluated and any of the above recovery methods were ordered."

Alabama Public Service Commission - No general rate cases. Use formula rate. Informal Docket No. U-5080 granted authorization to establish a regulatory asset account in which it would record incremental pension expense for 2013 and amortize this balance over a three year period.

Arizona Corporations Commission – 58497

California Public Utilities Commission - D.08-07-046 (SDG&E/Sempra); - D.12-11-051 (SCE); Decision (D.)09-09-020 (PG&E)

Colorado Public Utility Commission - C12-0494; R11-0743

Connecticut Department of Public Utility Control - Docket No. 10-12-02 Yankee Gas; Docket No. 08-12-06 Connecticut Natural Gas; Docket No. 08-12-07 Southern Connecticut Gas; Docket No. 09-12-05 Ct. Light & Power Company

Delaware Public Service Commission - Docket 09-414 Order No. 8063 (Delmarva Power & Light)

District of Columbia Public Service Commission - 12986; 14712
Florida Public Service Commission - PSC-09-0484-PAA-EI; PSC-09-0283-FOF-EI; PSC-10-0153-FOF-EI

Georgia Public Service Commission - Docket 30442: Docket 31647; Docket 31958

Hawaii Public Utility Commission - Docket No 2005-0315, filed Oct 28, 2010

Idaho Public Utilities Commission – 29505

Illinois Commerce Commission - 05-0597; 10-0467; 11-0721;12-0321

Indiana Utility Regulatory Commission - 43306; 43680; 43928; 43975

Iowa Utilities Board - RPU-2012-0002

Kansas Corporation Commission - 12-ATMG-564-RTS; 12-KCPE-764-RTS; 12-KGSG-835-RTS; 12-WSEE-112-RTS

Kentucky Public Service Commission - 2010-00116 -- Final order dated 10/21/10

Massachusetts Department of Public Utilities - DPU 08-27; DPU 11-43; DPU 12-25

Michigan Public Service Commission - U-16472; U-16794 p89 of the order

Minnesota Public Utilities Commission - E-002/GR-10-971; E-015/GR-09-1151

Mississippi Public Service Commission - 2003-UN-898; 2005-UN-503; 2009-UN-388; 2012-UN-139

New Hampshire Public Utilities Commission – 25 352

New Mexico Public Regulation Commission - 07-00077-UT; 06-00201-UT (PNM - Gas)

New Mexico Public Regulation Commission - 07-00319-UT (Southwestern Public Service Company)

Oklahoma Corporation Commission - 200800144; 201100087

Oregon Public Utility Commission - 12-473

Public Service Commission of West Virginia - 10- 0920-W-42T, West Virginia-American Order Issued 4-17-11; 11-1627-E-42T, Mountaineer Gas, Order Issued 10/31/12

Public Utilities Commission of Ohio - Columbus Southern Power 11-351--EL-AIR (see page 7 of report); Duke Energy 12-1682-EL-AIR; Duke Energy 12-1685-GA-AIR

Public Utilities Commission of Ohio - Ohio American Water 09-391-WS-AIR (See testimony of Syeda Choudhury)

Public Utility Commission of Texas - Docket No. 33309; Docket No. 38339

Public Utility Commission of Utah - Docket No. 07-035-93 - Order issued 8/11/08; Docket No. 09-035-23 - Order issued 2/18/10

Rhode Island Public Utilities Commission - 20943

South Carolina Public Service Commission - 2012-77; 2012-951

Vermont Public Service Department - not available

Wyoming Public Service Commission - 20000-336-ER-08; 20000-405-ER-11

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SUMMARY ADIT ALLOCATIONS TO CENTRAL GULF SERVICE AREA
For General Rate Case - Test Year Ended 9/30/2019

Estimated Accumulated Deferred Income Taxes for:	ADIT at 21%	Unamortized Excess ADIT - Bal at 9/30/2019	Total CGSA ADIT and Excess ADIT at 9/30/2019
Central Gulf Service Area Plant Assets Depreciation	(61,333,789)	(33,964,349)	(95,298,138)
Central Gulf Service Area Direct Plant Repairs	(18,562,936)	(10,622,000)	(29,184,936)
Subtotal CGSA Direct Plant Assets Depreciation	(79,896,725.03)	(44,586,349.40)	(124,483,074.43)
Central Gulf Service Area Other Rate Base Items	(5,420,956.13)	(3,136,046.79)	(8,557,002.92)
TGS Division Plant Assets Depreciation	(58,273.38)	(264,572.90)	(322,846.28)
ONEGAS Plant Assets Depreciation	(2,766,139.92)	(1,541,999.99)	(4,308,139.91)
Central Gulf Service Area NOL	36,180,704.51	21,068,802.65	57,249,507.16
ADFIT - Accumulated Deferred Federal Income Taxes	(51,961,390)	(28,460,166)	(80,421,556)

Accumulated Deferred Income Tax - Central Gulf Service Area Plant Related Items

As of Sept 30, 2019 Town	Gross Book Basis	Book Reserve	Net Book Basis	Gross Tax Basis	Tax Reserve	Net Tax Basis	Difference in Net Plant Basis	Estimated ADIT Asset/(Liability) at 21%
Austin Area	551,978,335	(149,421,920)	402,556,415	294,396,037	(174,642,704)	119,753,332		
Buda	622,658	(17,663)	604,995	596,261	(92,238)	504,023		
Kyle	6,901,441	(435,880)	6,465,561	4,314,059	(1,592,398)	2,721,661		
Nixon	699,670	192,734	892,404	507,360	(224,509)	282,852		
Other South Tx Towns	30,951,382	(3,945,350)	27,006,032	13,377,941	(7,319,390)	6,058,552		
Total Central Texas	591,153,485	(153,628,078)	437,525,407	313,191,659	(183,871,239)	129,320,420		
Galveston	34,522,582	(11,348,593)	23,173,989	18,845,888	(12,044,309)	6,801,579		
South Jefferson	66,324,468	(15,626,628)	50,697,840	31,319,306	(20,538,695)	10,780,611		
	100,847,050	(26,975,221)	73,871,828	50,165,194	(32,583,005)	17,582,190		
Central Gulf Service Area Direct Plant	692,000,535	(180,603,300)	511,397,235	363,356,853	(216,454,243)	146,902,610	364,494,625	(76,543,871)
			-			-		
Central Tx 101 Retirement Adjustments	(2,038,101)		(2,038,101.00)					
Central Tx 108 Retirement Adjustments		2,038,101	2,038,101.00					
Central Tx 108 Retirement Work in Progress Adj.		5,547,187	5,547,187.00					
Central Tx 101 Adjustment - OPC High Pressure Line	8,024,125		8,024,125.00					
Central Tx 108 Adjustment - OPC High Pressure Line		(2,973,659)	(2,973,659.00)					
Central Tx 101 Adjustments - Other	6,790		6,789.57					
Central Tx 106 Adjustments	10,297,228		10,297,227.97					
Central Tx 108/111 Adjustments - Other		1,212,582	1,212,582.03					
Subtotal Central Tx Adjustments	16,290,042	5,824,211	22,114,253	5,459,043	1,451,290	6,910,334	15,203,919	(3,192,823)
Gulf Coast 101 Retirement Adjustments	(1,046,273)		(1,046,273.00)					
Gulf Coast 108 Retirement Adjustments		1,046,273	1,046,273.00					
Gulf Coast 108 RWIP Adjustments		611,396	611,396.00					
Gulf Coast 101 Adjustments - Other	(521)		(520.74)					
Gulf Coast 106 Adjustments	380,477		380,476.94					
Gulf Coast 108/111 Adjustments - Other		193,838	193,838.39					
Subtotal Gulf Coast Adjustments	(666,317)	1,851,507	1,185,191	189,005	234,135	423,140	762,051	(160,031)
Subtotal Adjustments	15,623,725	7,675,718	23,299,443	5,648,048	1,685,425	7,333,473	15,965,970	(3,352,854)
Adjusted Central Gulf Service Area	**707,624,260**	**(172,927,581)**	**534,696,678**	**369,004,901**	**(214,768,818)**	**154,236,083**	**380,460,595**	**(79,896,725)**
TGS Division (Allocated to Central Gulf Service Area)	**3,654,287**	**(1,378,530)**	**2,275,758**	**3,930,880**	**(1,932,615)**	**1,998,265**	**277,492**	**(58,273)**
ONEGas (Allocated to Central Gulf Service Area)	**26,582,838**	**(7,876,676)**	**18,706,162**	**17,646,337**	**(12,112,269)**	**5,534,068**	**13,172,095**	**(2,766,140)**

Accumulated Deferred Income Tax Analysis For Central Gulf Service Area Other Rate Base Items

	Balance Sheet Impact per Book	Balance Sheet Impact per Tax	Difference	Estimated ADIT Asset/(Liability)
Pension/OPEB Expense Regulatory Deferrals	1,944,459	-	1,944,459	(408,336)
Prepaid Pension (funding in excess of FAS87 expense)	23,340,795	-	23,340,795	(4,901,567)
Section 8.209 Deferral	528,823	-	528,823	(111,053)
Total Other Rate Base Items				(5,420,956)

Summary of Central Gulf Service Area NOL as of June 30, 2019 with Update to Sept 30, 2019

Line	Description	Notes	Division Office Cost Centers, Incl Corp Alloc (a)	Central (b)	Gulf (c)	Total Central Gulf Service Area Including Allocated Amts (d)
1	Total Pre Tax Net (Income)/loss per Book thru June 2019		(1,565,071,987)	347,819,624	53,465,300	(326,367,125)
2	Reclass Gas Cost between Jurisdictions and Division Office Cost Centers	1	2,604,525,522	(933,224,527)	(176,878,558)	100,824,175
3	Subtotal (Income)/loss per Book thru June 2019		1,039,453,535	(585,404,903)	(123,413,257)	(225,542,950)
4	Remove Non Utility Expenses net of revenues (charitable, civic, legislative, merchandising, etc.)		(47,774,712)	(4,675,669)	(824,488)	(27,712,149)
5	Remove 50% of Meals Expense		(2,205,188)	(569,755)	(290,847)	(1,885,865)
6	Remove Non-deductible Parking (Including Allocated portion of Shared Costs)			(118,925)	(21,816)	(140,741)
7	Reverse Pension/OPEB Expense Regulatory Deferrals			1,856,196	88,263	1,944,459
8	Reflect Addition Pension Deductions per Tax based on Funding level			19,963,666	3,377,129	23,340,795
9	Reverse Section 8.209 Deferral			468,231	60,592	528,823
10	Subtotal Adjusted (Income)/loss per Book thru June 2019		989,473,636	(568,481,159)	(121,024,426)	(229,467,628)
11	Reverse Book Depreciation	2	(150,377,220)	(93,220,494)	(25,614,798)	(188,750,474)
12	Deduct Allocated OneGas Tax Depreciation	4	66,446,575			30,893,139
13	Deduct TGS Division Tax Depreciation	4	8,253,107	464,579,704	91,197,194	559,614,032
14	Total Depreciation Related Adjustments Impacting Jurisdiction		(75,677,537)	371,359,210	65,582,396	401,756,697
15	Subtotal - Pre Tax Net (Income)/loss after adjustments		913,796,098	(197,121,948)	(55,442,030)	172,289,069
16	Allocate to Central Gulf Service Area		46.4932%	100.0000%	100.0000%	
17	Subtotal - Jurisdictional Pre Tax Net (Income)/loss before Tax Adj	3	424,853,048	(197,121,948)	(55,442,030)	172,289,069
18	Tax Rate		21%	21%	21%	21%
19	NOL ADIT Adjustment	5 and 6	89,219,140	(41,395,609)	(11,642,826)	36,180,705
						0

Notes:

1. Reclassification of cost to align jurisdiction gas cost revenue with gas cost expense

2. Prior to 2009 Depreciation for all TGS jurisdictions was recorded to division office rather than local jurisdiction cost centers. Since book depreciation is entirely reversed and replaced with tax depreciation, no reclassification of book depreciation was made above. Instead, book depreciation is reversed from the cost center group to which it was actually recorded

3. Allocation of Shared Costs to Service Area

	Alloc to Central	Alloc to Gulf	Total Alloc to Central Gulf
Allocable Shared Service Costs	913,796,098	913,796,098	
Central Customers as of 6/30/2019	263,781		
Gulf Customers as of 6/30/2019		44,622	
Total TGS Customers as of 6/30/2019	663,330	663,330	
Allocation Factor	39.7662%	6.7270%	46.4932%
	363,381,984	61,471,064	424,853,048

4 - "Tax Depreciation" represents all book vs. tax plant-related timing differences including the excess of tax depreciation (including tax bonus depreciation) over book depreciation; amounts expensed per tax as repairs expense but but capitalized as additions per book; cost of removal deducted as expense per tax but taken to accumulated depreciation per book; the impact of any write off to expense of the net book value for tax purposes at the time of retirement, and CIAC credits taxed as income when received for tax purposes but deducted from plant basis per book.

5. If the NOL ADIT adjustment is a credit amount (negative amount), the carryforward to the summary ADFIT page will be zero since that means that there is net taxable income rather than a tax NOL (net operating loss).

6. If adding the NOL to the jurisdiction's other ADFIT components results in a net ADFIT debit, only add in only enough of the NOL above to bring the total net ADFIT for the jurisdiction to $0.

TGS Division Assets
Estimated Accumulated Deferred Income Tax Analysis
As of September 30, 2019

Row	A	B	C	D	E	G	H	I	K	L
7										**TOTAL ADIT**
8			(1010 & 1060)	(1080100 & 1110)		(1010 & 1060)	(1080100 & 1110)	**Net**		**Asset/(Liability)**
9			**Book**	**Book**	**Net Book**	**Tax**	**Tax**	**Tax**	**Timing**	**(incl. Excess ADIT)**
10			**Basis**	**Reserve**	**Basis**	**Basis**	**Reserve**	**Basis**	**Difference**	**09/30/2019**
11										21% tax rate
12	TGS Division unadjusted		4,884,925	(342,878)	4,542,047	5,403,028	(4,162,266)	1,240,762	3,301,286	(693,270)
14	**Adjustments**									
15	301	Organization Costs	(127,437)	127,437	-	(104,835)		(104,835)	104,835	(22,015)
16	303	Intangible Property	(278,560)	278,560	-	(229,154)		(229,154)	229,154	(48,122)
17	376	Mains	-		-			-	-	-
18	389	Land & Land Rights	527,777		527,777	527,777		527,777	-	-
19	390.1	Structures & Improvements	2,907,882	(5,304)	2,902,578	2,907,882		2,907,882	(5,304)	1,114
20	390.2	Leasehold Equipment	(43,351)	43,745	394	(43,351)		(43,351)	43,745	(9,186)
21	390.21	Leasehold Equipment EOL			-			-	-	-
22	391.1	Office Furniture & Fixtures	-	(48,803)	(48,803)	-	-	-	(48,803)	10,249
23	391.2	Data Processing Equipment			-			-	-	-
24	391.2	Radio Towers			-			-	-	-
25	391.3	Office Machines			-			-	-	-
26	391.4	Audio Visual Equipment			-			-	-	-
27	391.5	Artwork			-			-	-	-
28	391.6	Purchased Software			-	-		-	-	-
29	391.9	Micro Computer Equipment	(11,143)	(2,992,047)	(3,003,190)	(6,475)	5,407	(1,068)	(3,002,122)	630,446
30	392.2	Pickup Trucks and Vans			-			-	-	-
31	392.3	Trucks 3/4 to 3 Ton			-			-	-	-
32	392.5	Trailers			-			-	-	-
33	392.6	Aircraft			-			-	-	-
34	394	Tools	(262)	(1,108)	(1,370)	(131)	91	(40)	(1,330)	279
35	394.2	Shop Equipment			-			-	-	-
36	397	Communication Equipment	-	(24,615)	(24,615)			-	(24,615)	5,169
37	398	Miscellaneous Equipment		-	-			-	-	-
38	Total Adjustments		2,974,907	(2,622,136)	352,771	3,051,713	5,498	3,057,211	(2,704,441)	567,934
40	TGS Division Adjusted		7,859,832	(2,965,014)	4,894,818	8,454,741	(4,156,768)	4,297,973	596,845	(125,336)
41	CTGCSA Allocation Factor		46.4932%	46.4932%	46.4932%	46.4932%	46.4932%	46.4932%	46.4932%	46.4932%
42	Total Division Allocated to CTGCSA		3,654,287	(1,378,530)	2,275,758	3,930,880	(1,932,615)	1,998,265	277,492	(58,273)
44		Per WKP C.b.1 Post Test Year Div	4,423,681							
45		Per WKP C-1.b.1 Post Test Yr Div	3,436,151				Service Area's % of customers			46.4932%
46		Per WKP D.b.1 Post Test Yr Div		(2,965,014)			(Input jurisdiction's factor on version pasted to juridictional ADIT file)			
47			7,859,832	(2,965,014)						
48		Difference	(0)	-			Service Area's allocated piece of ADFIT			(58,273)

ONEGAS, Inc. (Corporate Assets)
Estimated Accumulated Deferred Income Tax Analysis
As of Sept 30, 2019

Plant Acct	Description	A (1010 & 1060) Book Basis	B (1080100 & 1110) Book Reserve	Net Book Basis	C (1010 & 1060) Gross Tax Basis	D (1080100 & 1110) Tax Reserve	Net Tax Basis	Total Timing Difference	Estimated ADIT Asset/(Liability) 9/30/2019	Allocation Factor to TGS
									21% tax rate	
	Total ONEGAS unadjusted	241,036,494.14	(75,362,258.66)	165,674,235	162,825,248	(114,947,039)	47,878,208	117,796,027	(24,737,166)	
389	Land & Land Rights	-	-	-	-	-	-	-	-	25.01%
391.1	Office Furniture & Equipment	255,010.17	(1,415.66)	253,595	255,011	(4,336)	250,674	2,920	(613)	25.01%
390.2	Leasehold Improvements	5,382,079.48	(2,133,609.48)	3,248,470	4,085,993	(582,723)	3,503,270	(254,800)	53,508	25.01%
391.1	Office Furniture & Equipment	3,605,934.31	(858,752.83)	2,747,181	433,067	(15,930)	417,138	2,330,044	(489,309)	25.01%
390.19	Airplane Hanger Furniture	11,869.56	(3,388.12)	8,481	-	-	-	8,481	(1,781)	25.01%
391.3	Office Machines	36,236.76	(14,326.54)	21,910	15,646	(567,812)	(552,165)	574,075	(120,556)	25.01%
391.4	Audio Visual Equipment	1,402,299.01	(1,090,137.83)	312,161	755,768	(665,652)	90,115	222,046	(46,630)	25.01%
391.5	Artwork	49,413.97	(10,635.21)	38,779	-	-	-	38,779	(8,144)	25.01%
391.6	Purchased Software	117,635,422.55	(27,642,554.79)	89,992,868	58,416,474	(25,102,761)	33,313,713	56,679,154	(11,902,622)	25.01%
391.6	Banner Software	5,471,958.05	(1,292,481.60)	4,179,476	12,465,023	(13,493,271)	(1,028,248)	5,207,724	(1,093,622)	30.41%
391.6	PowerPlant	870,000.01	(361,608.25)	508,392	870,000	(356,874)	513,126	(4,734)	994	24.02%
391.6	Maximo	3,117,560.99	(2,253,129.05)	864,432	3,117,561	(3,357,301)	(239,740)	1,104,172	(231,876)	24.71%
391.6	Concur Project	47,647.71	(47,647.71)	-	47,648	(47,648)	-	-	-	27.95%
391.6	Journey- Employee - ODC Distrigas	69,580,939.55	(26,272,810.56)	43,308,129	38,295,750	(33,222,433)	5,073,317	38,234,812	(8,029,311)	25.01%
391.6	Journey - Employee Count	1,848,836.03	(833,622.36)	1,015,214	-	-	-	1,015,214	(213,195)	27.95%
391.6	Ariba Software	-	-	-	-	-	-	-	-	30.96%
391.6	Ariba Software	903,328.29	(141,533.60)	761,795			-	761,795	(159,977)	30.96%
391.8	Micro Computer Equipment	16,975,889.07	(4,466,695.70)	12,509,193	10,434,136	(3,949,873)	6,484,263	6,024,930	(1,265,235)	25.01%
391.81	Aircraft Computer Equipment	130,857.17	(82,058.30)	48,799			-	48,799	(10,248)	25.01%
392.6	Aircraft	13,608,722.55	(7,845,188.51)	5,763,534	13,541,078	(13,515,102)	25,976	5,737,558	(1,204,887)	25.01%
397	Communicaton Equipment	102,488.60	(10,662.56)	91,826	20,092,094	(20,065,323)	26,771	65,055	(13,662)	25.01%
	Total ONEGAS unadjusted	241,036,493.83	(75,362,258.66)	165,674,235.17	162,825,248.21	(114,947,039.00)	47,878,209.21	117,796,025.96	(24,737,166.00)	
		(0)	-	0	(0)	0	(1)	1	-	
Adjustments										
389	Land & Land Rights	-	-	-	-	-	-	-	-	25.01%
390.2	Leasehold Improvements	(52.09)		(52)	(52)	3	(49)	(3)	1	25.01%
390.19	Airplane Hanger Furniture	(11,869.56)	3,388.12	(8,481)	-	-	-	(8,481)	1,781	25.01%
391.5	Artwork	(49,413.97)	10,635.21	(38,779)	-	-	-	(38,779)	8,144	25.01%
391.6	Banner Software	(355.00)		(355)	(178)	-	(178)	(178)	37	30.41%
391.6	Purchased Software	(157,783.28)	56,619.44	(101,164)	(78,892)	65,743	(13,149)	(88,015)	18,483	25.01%
391.6	Journey- Employee - ODC Distrigas	(12,655.29)		(12,655)	(6,328)	-	(6,328)	(6,328)	1,329	25.01%
391.8	Micro Computer Equipment	(280.25)	-	(280)	(140)	-	(140)	(140)	29	25.01%
391.81	Aircraft Computer Equipment	(130,857.17)	82,058.30	(48,799)	(65,429)	65,426	(3)	(48,796)	10,247	25.01%
392.6	Aircraft	(13,608,722.55)	7,845,188.51	(5,763,534)	(13,541,078)	13,515,102	(25,976)	(5,737,558)	1,204,887	25.01%
397.2	Communicaton Equipment		-	-	-	-	-	-	-	25.01%
	Subtotal Adjustments	(13,971,989.16)	7,997,889.58	(5,974,099.58)	(13,692,095.36)	13,646,273.80	(45,821.55)	(5,928,278.03)	1,244,938.00	
	Total Adjusted	227,064,504.67	(67,364,369.08)	159,700,135.59	149,133,152.86	(101,300,765.20)	47,832,387.66	111,867,747.93	(23,492,228.00)	
				-					1	

Plant Acct	Description	Timing Diff Allocated to TGS Divison	Deferred Tax Allocated to TGS Divison	(1010 & 1060) Book Basis Allocated to TGS	(1080100 & 1110) Book Reserve Allocated to TGS	Net Book Basis Allocated to TGS	(1010 & 1060) Gross Tax Basis Allocated to TGS	(1080100 & 1110) Tax Reserve Allocated to TGS	Net Tax Basis Allocated to TGS	Total Allocated Timing Difference	Allocated TOTAL ADIT Asset/(Liability) (incl. Excess ADIT) 9/30/2019
											21% tax rate
	Total ONEGAS unadjusted			60,670,169	(18,941,838)	41,728,332	41,379,064	(29,464,633)	11,914,431	29,813,901	(6,260,919)
389	Land & Land Rights	-	-	-	-	-	-	-	-	-	-
391.1	Office Furniture & Equipment	730	(153)	63,778	(354)	63,424	63,778	(1,085)	62,694	730	(153)
390.2	Leasehold Improvements	(63,725)	13,382	1,346,058	(533,616)	812,442	1,021,907	(145,739)	876,168	(63,725)	13,382
391.1	Office Furniture & Equipment	582,744	(122,376)	901,844	(214,774)	687,070	108,310	(3,984)	104,326	582,744	(122,376)
390.19	Airplane Hanger Furniture	2,121	(445)	2,969	(847)	2,121	-	-	-	2,121	(445)
391.3	Office Machines	143,576	(30,151)	9,063	(3,583)	5,480	3,913	(142,010)	(138,096)	143,576	(30,151)
391.4	Audio Visual Equipment	55,534	(11,662)	350,715	(272,643)	78,072	189,017	(166,480)	22,538	55,534	(11,662)
391.5	Artwork	9,699	(2,037)	12,358	(2,660)	9,699	-	-	-	9,699	(2,037)
391.6	Purchased Software	14,175,457	(2,976,846)	29,420,619	(6,913,403)	22,507,216	14,609,960	(6,278,200)	8,331,760	14,175,457	(2,976,846)
391.6	Banner Software	1,583,673	(332,571)	1,664,027	(393,045)	1,270,982	3,790,623	(4,103,314)	(312,691)	1,583,673	(332,571)
391.6	PowerPlant	(1,137)	239	208,931	(86,840)	122,090	208,931	(85,703)	123,227	(1,137)	239
391.6	Maximo	272,826	(57,293)	770,306	(556,717)	213,589	770,306	(829,543)	(59,237)	272,826	(57,293)
391.6	Concur Project	-	-	13,317	(13,317)	-	13,317	(13,317)	-	-	-
391.6	Journey- Employee - ODC Distrigas	9,562,527	(2,008,131)	17,402,193	(6,570,830)	10,831,363	9,577,767	(8,308,931)	1,268,837	9,562,527	(2,008,131)
391.6	Journey - Employee Count	283,752	(59,588)	516,750	(232,997)	283,752	-	-	-	283,752	(59,588)
391.6	Ariba Software	-	-	-	-	-	-	-	-	-	-
391.6	Ariba Software	235,852	(49,529)	279,670	(43,819)	235,852	-	-	-	235,852	(49,529)
391.8	Micro Computer Equipment	1,506,835	(316,435)	4,245,670	(1,117,121)	3,128,549	2,609,577	(987,863)	1,621,714	1,506,835	(316,435)
391.81	Aircraft Computer Equipment	12,205	(2,563)	32,727	(20,523)	12,205	-	-	-	12,205	(2,563)
392.6	Aircraft	1,434,963	(301,342)	3,403,542	(1,962,082)	1,441,460	3,386,624	(3,380,127)	6,496	1,434,963	(301,342)
397	Communicaton Equipment	16,270	(3,417)	25,632	(2,667)	22,966	5,025,033	(5,018,337)	6,695	16,270	(3,417)
	Total ONEGAS unadjusted	29,813,901	(6,260,919)	60,670,169	(18,941,838)	41,728,332	41,379,064	(29,464,633)	11,914,431	29,813,901	(6,260,919)
Adjustments											
389	Land & Land Rights	-	-	-	-	-	-	-	-	-	-
390.2	Leasehold Improvements	(1)	0	(13)	-	(13)	(13)	1	(12)	(1)	0
390.19	Airplane Hanger Furniture	(2,121)	445	(2,969)	847	(2,121)	-	-	-	(2,121)	445
391.5	Artwork	(9,699)	2,037	(12,358)	2,660	(9,699)	-	-	-	(9,699)	2,037
391.6	Banner Software	(54)	11	(108)	-	(108)	(54)	-	(54)	(54)	11
391.6	Purchased Software	(22,013)	4,623	(39,462)	14,161	(25,301)	(19,731)	16,442	(3,288)	(22,013)	4,623
391.6	Journey- Employee - ODC Distrigas	(1,583)	332	(3,165)	-	(3,165)	(1,583)	-	(1,583)	(1,583)	332
391.8	Micro Computer Equipment	(35)	7	(70)	-	(70)	(35)	-	(35)	(35)	7
391.81	Aircraft Computer Equipment	(12,204)	2,563	(32,727)	20,523	(12,205)	(16,364)	16,363	(1)	(12,204)	2,563
392.6	Aircraft	(1,434,963)	301,342	(3,403,542)	1,962,082	(1,441,460)	(3,386,624)	3,380,127	(6,496)	(1,434,963)	301,342
397.2	Communicaton Equipment	-	-	-	-	-	-	-	-	-	-
	Subtotal Adjustments	(1,482,672)	311,361	(3,494,414)	2,000,272	(1,494,141)	(3,424,403)	3,412,933	(11,470)	(1,482,672)	311,361
	Total Adjusted	28,331,229	(5,949,558)	57,175,756	(16,941,566)	40,234,190 (A)	37,954,661	(26,051,700)	11,902,961	28,331,229	(5,949,558)
	Service Area's % of customers		46.4932%	46.4932%	46.4932%	46.4932%	46.4932%	46.4932%	46.4932%	46.4932%	46.4932%
	(Input jurisdiction's factor on version pasted to juridictional ADIT file)			26,582,838	(7,876,676)	18,706,162	17,646,337	(12,112,269)	5,534,068	13,172,095	(2,766,140)
	Service Area's allocated piece of ADFIT on plant		(2,766,140)								

Per WKP C.c Corp Plant	48,700,525	
Per WKP C-1.c Corp CCNC	8,475,214	
Per WKP D.c Corp Reserves		(16,941,570)
	57,175,739	(16,941,570)
Difference (immaterial/rounding)	16.62	4.01

	A	B	C	D	E	F	G	H	I	J	K	L
1												
2	**Calculation of ADIT re CGSA Repair Adjustment**											
3												
4												
5		**Per Tax Report 30:**										
6		2008 Tax Repair Blankets	2008 Tax Repair Bonus	2008 Tax Repair Bonus Depr Adju	2008 Tax Repair Expense	2009 Tax Repair Blankets	2009 Tax Repair Bonus	2009 Tax Repair Bonus Depr Adju	2009 Tax Repair Expense	Tax Expensing (2010-2018 Tax Repair)	Total Tax Repairs Adjustment	ADIT Asset/(Liability) at 21%
7	Galveston	(2,562)	72,631	219,887	(346,709)	(162,975)	102,808	385,874	(1,004,946)	(3,190,231)	(3,926,223)	(824,507)
8	South Jefferson County	(1,778,131)	1,004,601	998,600	(3,070,267)	(196,135)	165,813	1,164,659	(3,202,371)	(8,295,186)	(13,208,417)	(2,773,768)
9	Total Gulf Coast Area	(1,780,693)	1,077,232	1,218,487	(3,416,976)	(359,111)	268,621	1,550,533	(4,207,316)	(11,485,417)	(17,134,641)	(3,598,275)
10												
11	Buda	-	-	-	-	-	-	-	-	-	-	-
12	Central Texas	(5,041,909)	2,802,776	2,756,907	(4,548,007)	(1,346,554)	680,764	777,787	(3,453,716)	(57,218,049)	(64,590,001)	(13,563,900)
13	Kyle	-	-	549	(1,134)	-	-	-	(1,624)	(114)	(2,323)	(488)
14	Nixon	-	-	-	-	(2,462)	1,231		-	(72,894)	(74,124)	(15,566)
15	South Texas	(208,536)	84,461	339,760	(911,994)	(166,486)	89,011	229,509	(590,342)	(5,459,225)	(6,593,842)	(1,384,707)
16	Total Central Texas Area	(5,250,445)	2,887,237	3,097,217	(5,461,135)	(1,515,503)	771,006	1,007,296	(4,045,682)	(62,750,282)	(71,260,291)	(14,964,661)
17												
18	Total Central Gulf Service Area	(7,031,138)	3,964,468	4,315,704	(8,878,111)	(1,874,613)	1,039,627	2,557,829	(8,252,998)	(74,235,699)	(88,394,931)	(18,562,936)
19												
20												
21												

	A	B	C	D	E	F	G	H	I	J
1	**ARAM Estimate for amounts attributed TO the Central/Gulf Coast SERVICE ARE/**									
2	**9.30.2019**									
3										
4										
5										
6	**Estimated Accumulated Deferred Income Taxes for:**		**Excess ADIT**		**Protected**	**Unprotected**		**TGS Amortization Amount**	**ONE Gas Amortization Amount**	**2018 Amortization**
7	**Gulf Coast Service Area Plant Assets Depreciatior**		(33,964,349)		(33,964,349)			(33,964,349)		290,226
8	**Gulf Coast Service Area Repairs**		(10,622,000)			(10,622,000)		(10,622,000)		999,021
9	**Gulf Coast Service Area Other Rate Base Items**		(3,136,047)			(3,136,047)		(3,136,047)		313,605
10	**TGS Division Plant Assets Depreciation**		(264,573)		(264,573)			(264,573)		65,467
11	**ONEGAS Plant Assets Depreciation**		(1,542,000)		(1,542,000)				(1,542,000)	183,881
12	**Gulf Coast Service Area NOL**		21,068,802		21,068,802			21,068,802		(566,040)
13										
14	**ADFIT - Accumulated Deferred Federal Income Taxes**		(28,460,167)		(14,702,120)	(13,758,047)		(26,918,167)	(1,542,000)	1,286,160
15										
16	Percent Protected				52%					
17	**GCSA without Grossup**									
18			TGS Amortization	ONE Gas Amortization	TGS NOL	OGS NOL		Total Amortization		
19	Year 1 - 2018 Actuals		$ 1,668,319	$ 183,881	$ (566,040)	$ 566,040		$ 1,286,160		
20										

CTGCSA - Central Texas GCSA Combined

	A	B	C	D	E	F	G	H	I	J	K	L
16		Rate Filing	Sum of Beg APB11 DIT	Sum of End APB11 DIT	Sum of Beg Timing Diff	Sum of End Timing Diff	Sum of APB11 DIT Provision	Sum of APB11 DIT Reversal	Sum of Beg FAS109 DIT	Sum of Beg Reg Liab Pre Grossup	Sum of Reg Liability Reversal	
17	2017		**98,033,074**	**109,248,303**	**280,094,497**	**312,138,008**	**-**	**-**	**109,248,303**	**(43,699,321)**		
18	2018		109,248,303	110,223,170	312,138,008	322,919,508	3,509,045	(2,534,177)	110,223,170	**(42,410,074)**	1,289,247	2.95%

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PowerTax Deferred Tax Summary Report

2018 AS FILED Tax Return FINAL
091 Texas Gas Service

Grouped By: Total Tax Classes

Jurisdiction: Federal Rate Cas Tax Year: 2018	Beginning Difference	Current Difference	Ending Difference	Beginning APB11 DFIT Balance	Current DFIT	Ending APB11 DFIT Balance	End FAS109 Liability @ Stat Rate	Regulatory Asset Before Gross-Up	Regulatory Liab Before Gross-Up	Regulatory Asset After Gross-Up	Regulatory Liab After Gross-Up
TGS Fed RC M/L	$240,779,360.86	$10,291,630.93	$251,070,991.79	$84,272,776.19	$1,871,016.51	$86,143,792.70	$52,724,908.28	($0.01)	($33,418,884.41)	($0.02)	($42,302,385.33)
Depreciation Difference	**$240,779,360.86**	**$10,291,630.93**	**$251,070,991.79**	**$84,272,776.19**	**$1,871,016.51**	**$86,143,792.70**	**$52,724,908.28**	**($0.01)**	**($33,418,884.41)**	**($0.02)**	**($42,302,385.33)**
Federal Rate Case Amortization	$0.00	$0.01	$0.01	$9,990,210.32	($999,021.08)	$8,991,189.24	$0.00	$0.00	($8,991,189.24)	$0.00	($8,991,189.24)
Depreciation Difference	**$0.00**	**$0.01**	**$0.01**	**$9,990,210.32**	**($999,021.08)**	**$8,991,189.24**	**$0.00**	**$0.00**	**($8,991,189.24)**	**$0.00**	**($8,991,189.24)**
TGS Fed RC 2008 Tax Rep Blank 4	$5,136,721.35	($166,537.89)	$4,970,183.46	$1,078,711.47	($34,972.95)	$1,043,738.52	$1,043,738.53	$0.00	$0.00	$0.00	$0.01
TGS Fed RC 2008 Tax Rep Exp 48	$5,987,626.68	($218,751.14)	$5,768,875.54	$1,257,401.62	($45,937.74)	$1,211,463.88	$1,211,463.86	$0.02	($0.04)	$0.03	($0.05)
TGS Fed RC 2009 Tax Rep Blank 4	$1,449,815.29	($43,938.41)	$1,405,876.88	$304,461.21	($9,227.07)	$295,234.14	$295,234.14	($0.00)	$0.01	($0.01)	$0.01
TGS Fed RC 2009 Tax Rep Exp 48	$6,258,897.93	($206,535.59)	$6,052,362.34	$1,314,368.59	($43,372.48)	$1,270,996.11	$1,270,996.09	($0.01)	($0.01)	($0.01)	($0.01)
TGS Fed RC Tax Expensing	$55,931,449.34	$11,097,272.16	$67,028,721.50	$11,745,604.40	$2,330,427.17	$14,076,031.57	$14,076,031.52	$0.22	($0.28)	$0.28	($0.35)
Book Overhead	**$74,764,510.59**	**$10,461,509.13**	**$85,226,019.72**	**$15,700,547.29**	**$2,196,916.93**	**$17,897,464.22**	**$17,897,464.14**	**$0.24**	**($0.31)**	**$0.30**	**($0.40)**
TGS Fed RC 2008 Tax Rep Bonus	($1,625,441.46)	$195,009.52	($1,430,431.94)	($341,342.72)	$40,952.01	($300,390.71)	($300,390.71)	($0.02)	$0.02	($0.03)	$0.03
TGS Fed RC 2008 Tax Rep Bonus-	($1,346,975.30)	$217,338.63	($1,129,636.67)	($282,864.82)	$45,641.11	($237,223.71)	($237,223.70)	$0.01	$0.00	$0.01	$0.01
TGS Fed RC 2009 Tax Rep Bonus	($823,248.50)	$79,076.63	($744,171.87)	($172,882.19)	$16,606.11	($156,276.08)	($156,276.09)	($0.00)	($0.01)	($0.00)	($0.01)
TGS Fed RC 2009 Tax Rep Bonus-	($689,230.16)	$45,527.92	($643,702.24)	($144,738.34)	$9,560.87	($135,177.47)	($135,177.47)	$0.00	($0.00)	$0.00	($0.00)
TGS Fed RC 8.209 ROE	($2,880,851.67)	($577,020.97)	($3,457,872.64)	($604,978.88)	($121,174.45)	($726,153.33)	($726,153.25)	($0.01)	$0.09	($0.02)	$0.11
TGS Fed RC Book-Tax Difference	$1,095,154.54	($456,502.38)	$638,652.16	$229,982.45	($95,865.50)	$134,116.95	$134,116.95	$0.01	($0.00)	$0.01	($0.00)
TGS Fed RC CIAC	($15,968,890.90)	($5,400,481.06)	($21,369,371.96)	($3,353,467.08)	($1,134,100.98)	($4,487,568.06)	($4,487,568.11)	($0.26)	$0.21	($0.33)	$0.27
TGS Fed RC Fed RC Only B/T Diff	$726,016.90	($759,484.20)	($33,467.30)	$152,463.56	($159,491.63)	($7,028.07)	($7,028.13)	$0.02	($0.08)	$0.02	($0.10)
TGS Fed RC Non-Fed/State B/T Di	$18,107,603.59	($3,315,105.06)	$14,792,498.53	$3,802,596.78	($696,172.05)	$3,106,424.73	$3,106,424.69	$0.07	($0.10)	$0.08	($0.13)
Tax Overhead	**($3,405,862.96)**	**($9,971,640.97)**	**($13,377,503.93)**	**($715,231.24)**	**($2,094,044.51)**	**($2,809,275.75)**	**($2,809,275.83)**	**($0.20)**	**$0.13**	**($0.26)**	**$0.16**
Total Tax Classes	**$312,138,008.49**	**$10,781,499.10**	**$322,919,507.59**	**$109,248,302.56**	**$974,867.85**	**$110,223,170.41**	**$67,813,096.59**	**$0.02**	**($42,410,073.84)**	**$0.03**	**($51,293,574.81)**
Jurisdiction Totals:	**$312,138,008.49**	**$10,781,499.10**	**$322,919,507.59**	**$109,248,302.56**	**$974,867.85**	**$110,223,170.41**	**$67,813,096.59**	**$0.02**	**($42,410,073.84)**	**$0.03**	**($51,293,574.81)**
Company Totals:	**$312,138,008.49**	**$10,781,499.10**	**$322,919,507.59**	**$109,248,302.56**	**$974,867.85**	**$110,223,170.41**	**$67,813,096.59**	**$0.02**	**($42,410,073.84)**	**$0.03**	**($51,293,574.81)**

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2018 AS FILED Tax Return FINAL
091 Texas Gas Service
PowerTax Deferred Tax Summary Report
Grouped By: Total Tax Classes

Jurisdiction : Federal Rate Case Tax Year : 2018	Beginning Difference	Provision	Reversal	Ending Difference	Beginning DFIT Balance	Current DFIT Provision	Current DFIT Reversal	Deferred Trans/Adj	Ending DFIT Balance
TGS Fed RC 2008 Tax Rep Blank 481a	$5,136,721.35	$0.00	($166,537.89)	$4,970,183.46	$1,078,711.47	$0.00	($34,972.95)	$0.00	$1,043,738.52
TGS Fed RC 2008 Tax Rep Exp 481a	$5,987,626.68	$0.00	($218,751.14)	$5,768,875.54	$1,257,401.62	$0.00	($45,937.74)	$0.00	$1,211,463.88
TGS Fed RC 2009 Tax Rep Blank 481a	$1,449,815.29	$0.00	($43,938.41)	$1,405,876.88	$304,461.21	$0.00	($9,227.07)	$0.00	$295,234.14
TGS Fed RC 2009 Tax Rep Exp 481a	$6,258,897.93	$0.00	($206,535.59)	$6,052,362.34	$1,314,368.59	$0.00	($43,372.48)	$0.00	$1,270,996.11
TGS Fed RC Tax Expensing	$55,931,449.34	$12,748,586.59	($1,651,314.43)	$67,028,721.50	$11,745,604.40	$2,677,203.19	($346,776.04)	$0.00	$14,076,031.57
Total Tax Classes	**$74,764,510.59**	**$12,748,586.59**	**($2,287,077.46)**	**$85,226,019.72**	**$15,700,547.29**	**$2,677,203.19**	**($480,286.28)**	**$0.00**	**$17,897,464.22**
Amortization Type Book Overhead Totals:	**$74,764,510.59**	**$12,748,586.59**	**($2,287,077.46)**	**$85,226,019.72**	**$15,700,547.29**	**$2,677,203.19**	**($480,286.28)**	**$0.00**	**$17,897,464.22**
Federal Rate Case Amortization	$0.00	$0.00	$0.01	$0.01	$9,990,210.32	$0.00	($999,021.08)	$0.00	$8,991,189.24
TGS Fed RC M/L	$240,779,360.86	$12,364,674.24	($2,073,043.31)	$251,070,991.79	$84,272,776.19	$2,596,581.59	($725,565.08)	$0.00	$86,143,792.70
Total Tax Classes	**$240,779,360.86**	**$12,364,674.24**	**($2,073,043.30)**	**$251,070,991.80**	**$94,262,986.51**	**$2,596,581.59**	**($1,724,586.16)**	**$0.00**	**$95,134,981.94**
Amortization Type Depreciation Difference Totals:	**$240,779,360.86**	**$12,364,674.24**	**($2,073,043.30)**	**$251,070,991.80**	**$94,262,986.51**	**$2,596,581.59**	**($1,724,586.16)**	**$0.00**	**$95,134,981.94**
TGS Fed RC 2008 Tax Rep Bonus Depr	($1,625,441.46)	$0.00	$195,009.52	($1,430,431.94)	($341,342.72)	$0.00	$40,952.01	$0.00	($300,390.71)
TGS Fed RC 2008 Tax Rep Bonus-Blank	($1,346,975.30)	$0.00	$217,338.63	($1,129,636.67)	($282,864.82)	$0.00	$45,641.11	$0.00	($237,223.71)
TGS Fed RC 2009 Tax Rep Bonus Depr	($823,248.50)	$0.00	$79,076.63	($744,171.87)	($172,882.19)	$0.00	$16,606.11	$0.00	($156,276.08)
TGS Fed RC 2009 Tax Rep Bonus-Blank	($689,230.16)	$0.00	$45,527.92	($643,702.24)	($144,738.34)	$0.00	$9,560.87	$0.00	($135,177.47)
TGS Fed RC 8.209 ROE	($2,880,851.67)	($848,171.31)	$271,150.34	($3,457,872.64)	($604,978.88)	($178,115.98)	$56,941.53	$0.00	($726,153.33)
TGS Fed RC Book-Tax Difference	$1,095,154.54	$0.00	($456,502.38)	$638,652.16	$229,982.45	$0.00	($95,865.50)	$0.00	$134,116.95
TGS Fed RC CIAC	($15,968,890.90)	($7,555,350.59)	$2,154,869.53	($21,369,371.96)	($3,353,467.08)	($1,586,623.62)	$452,522.65	$0.00	($4,487,568.06)
TGS Fed RC Fed RC Only B/T Diff	$726,016.90	$0.00	($759,484.20)	($33,467.30)	$152,463.56	$0.00	($159,491.63)	$0.00	($7,028.07)
TGS Fed RC Non-Fed/State B/T Diff	$18,107,603.59	$0.00	($3,315,105.06)	$14,792,498.53	$3,802,596.78	$0.00	($696,172.05)	$0.00	$3,106,424.73
Total Tax Classes	**($3,405,862.96)**	**($8,403,521.90)**	**($1,568,119.07)**	**($13,377,503.93)**	**($715,231.24)**	**($1,764,739.60)**	**($329,304.90)**	**$0.00**	**($2,809,275.75)**
Amortization Type Tax Overhead Totals:	**($3,405,862.96)**	**($8,403,521.90)**	**($1,568,119.07)**	**($13,377,503.93)**	**($715,231.24)**	**($1,764,739.60)**	**($329,304.90)**	**$0.00**	**($2,809,275.75)**
Jurisdiction Totals:	**$312,138,008.49**	**$16,709,738.93**	**($5,928,239.83)**	**$322,919,507.59**	**$109,248,302.56**	**$3,509,045.18**	**($2,534,177.34)**	**$0.00**	**$110,223,170.41**
Company Totals:	**$312,138,008.49**	**$16,709,738.93**	**($5,928,239.83)**	**$322,919,507.59**	**$109,248,302.56**	**$3,509,045.18**	**($2,534,177.34)**	**$0.00**	**$110,223,170.41**

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Ready

Texas Gas Service Company, a Division of ONE Gas, Inc.
CGSA ISOS RTCS TYE June 30, 2019
Updated for Known and Measurable Changes Through September 30, 2019

CTSA ADIT-EDIT WPs 6.30.2019 updt to 9.30 FINAL 12.5.2019
1 Summary

	A	B	C	D	E	F	G	H	I	J
1										
2	**SUMMARY ADIT ALLOCATIONS TO CENTRAL TEXAS SERVICE AREA**									
3	**For General Rate Case - Test Year Ended 9/30/2019**									
4										
5			**Unamortized**	**Total CTSA**						
6			**Excess ADIT -**	**ADIT and Excess**						
7	**Estimated Accumulated Deferred Income Taxes for:**	**ADIT at 21%**	**Bal at 9/30/2019**	**ADIT at 9/30/2019**						
8	**Central TexasService Area Plant Assets Depreciation**	(52,951,209)	(28,694,365)	(81,645,574)						
9	**Central Texas Service Area Direct Plant Repairs**	(14,964,661)	(8,319,002)	(23,283,663)						
10	**Subtotal CTSA Direct Plant Assets Depreciation**	(67,915,870)	(37,013,367)	(104,929,237)						
11	**Central Texas Service Area Other Rate Base Items**	(4,680,500)	(2,676,419)	(7,356,919)						
12	**TGS Division Plant Assets Depreciation**	(49,842)	(225,312)	(275,154)						
13	**ONEGAS Plant Assets Depreciation**	(2,365,913)	(1,308,791)	(3,674,704)						
14	**Central Texas Service Area NOL**	34,914,608	19,296,333	54,210,941						
15										
16	**ADFIT - Accumulated Deferred Federal Income Taxes**	(40,097,517)	(21,927,556)	(62,025,073)						
17										
18										
19										
20	**Accumulated Deferred Income Tax - Central Texas Service Area Plant Related Items**									
21										
22		**Gross**		**Net**	**Gross**		**Net**	**Difference**	**Estimated ADIT**	
23	**As of Sept 30, 2019**	**Book**	**Book**	**Book**	**Tax**	**Tax**	**Tax**	**in Net**	**Asset/(Liability)**	
24	**Town**	**Basis**	**Reserve**	**Basis**	**Basis**	**Reserve**	**Basis**	**Plant Basis**	**at 21%**	
25	Austin Area	551,978,335	(149,421,920)	402,556,415	294,396,037	(174,642,704)	119,753,332			
26	Buda	622,658	(17,663)	604,995	596,261	(92,238)	504,023			
27	Kyle	6,901,441	(435,880)	6,465,561	4,314,059	(1,592,398)	2,721,661			
28	Nixon	699,670	192,734	892,404	507,360	(224,509)	282,852			
29	Other South Tx Towns	30,951,382	(3,945,350)	27,006,032	13,377,941	(7,319,390)	6,058,552			
30	Total Central Texas	591,153,485	(153,628,078)	437,525,407	313,191,659	(183,871,239)	129,320,420	308,204,987	(64,723,047)	
31										
32	Central Tx 101 Retirement Adjustments	(2,038,101)		(2,038,101.00)						
33	Central Tx 108 Retirement Adjustments		2,038,101	2,038,101.00						
34	Central Tx 108 Retirement Work in Progress Adj.		5,547,187	5,547,187.00						
35	Central Tx 101 Adjustment - OPC High Pressure Line	8,024,125		8,024,125.00						
36	Central Tx 108 Adjustment - OPC High Pressure Line		(2,973,659)	(2,973,659.00)						
37	Central Tx 101 Adjustments - Other	6,790		6,789.57						
38	Central Tx 106 Adjustments	10,297,228		10,297,227.97						
39	Central Tx 108/111 Adjustments - Other		1,212,582	1,212,582.03						
40	Subtotal Central Tx Adjustments	16,290,042	5,824,211	22,114,253	5,459,043	1,451,290	6,910,334	15,203,919	(3,192,823)	
41										
42	**Adjusted Central Texas Service Area**	**607,443,527**	**(147,803,867)**	**459,639,660**	**318,650,702**	**(182,419,948)**	**136,230,754**	**323,408,906**	**(67,915,870)**	
43										
44	**TGS Division (Allocated to Central Texas Service Area)**	**3,125,557**	**(1,179,073)**	**1,946,483**	**3,362,129**	**(1,652,989)**	**1,709,141**	**237,343**	**(49,842)**	
45										
46	**ONEGas (Allocated to Central Texas Service Area)**	**22,736,625**	**(6,737,017)**	**15,999,609**	**15,093,127**	**(10,359,771)**	**4,733,355**	**11,266,253**	**(2,365,913)**	
47										
48										
49										
50	**Accumulated Deferred Income Tax Analysis For Central Texas Service Area Other Rate Base Items**									
51										
52		**Balance Sheet Impact per Book**	**Balance Sheet Impact per Tax**	**Difference**	**Estimated ADIT Asset/(Liability)**					
53										
54	Pension/OPEB Expense Regulatory Deferrals	1,856,196	-	1,856,196	(389,801)					
55										
56	Prepaid Pension (funding in excess of FAS87 expense)	19,963,666	-	19,963,666	(4,192,370)					
57										
58	Section 8.209 Deferral	468,231	-	468,231	(98,329)					
59										
60	Total Other Rate Base Items				(4,680,500)					

Summary of Central Texas Service Area NOL as of June 30, 2019 with Update to Sept 30, 2019

Row	Line	Description	Notes	Division Office Cost Centers, Incl Corp Alloc (a)	Central (b)	Total Central Texas Service Area Including Allocated Amts (d)
6	1	Total Pre Tax Net (Income)/loss per Book thru June 2019		(1,565,071,987)	347,819,624	(274,550,033)
8	2	Reclass Gas Cost between Jurisdictions and Division Office Cost Centers	1	2,604,525,522	(933,224,527)	102,496,301
9	3	Subtotal (Income)/loss per Book thru June 2019		1,039,453,535	(585,404,903)	(172,053,732)
11	4	Remove Non Utility Expenses net of revenues (charitable, civic, legislative, merchandising, etc.)		(47,774,712)	(4,675,669)	(23,673,856)
12	5	Remove 50% of Meals Expense		(2,205,188)	(569,755)	(1,446,675)
13	6	Remove Non-deductible Parking (Including Allocated portion of Shared Costs)			(118,925)	(118,925)
14	7	Reverse Pension/OPEB Expense Regulatory Deferrals			1,856,196	1,856,196
15	8	Reflect Addition Pension Deductions per Tax based on Funding level			19,963,666	19,963,666
16	9	Reverse Section 8.209 Deferral			468,231	468,231
17	10	Subtotal Adjusted (Income)/loss per Book thru June 2019		989,473,636	(568,481,159)	(175,005,094)
19	11	Reverse Book Depreciation	2	(150,377,220)	(93,220,494)	(153,019,800)
20	12	Deduct Allocated OneGas Tax Depreciation	4	66,446,575		26,423,278
21	13	Deduct TGS Division Tax Depreciation	4	8,253,107	464,579,704	467,861,651
22	14	Total Depreciation Related Adjustments Impacting Jurisdiction		(75,677,537)	371,359,210	341,265,129
24	15	Subtotal - Pre Tax Net (Income)/loss after adjustments		913,796,098	(197,121,948)	166,260,036
25	16	Allocate to Central Gulf Service Area		39.7662%	100.0000%	
26	17	Subtotal - Jurisdictional Pre Tax Net (Income)/loss before Tax Adj	3	363,381,984	(197,121,948)	166,260,036
28	18	Tax Rate		21%	21%	21%
30	19	NOL ADIT Adjustment	5 and 6	76,310,217	(41,395,609)	34,914,608
31						0

Notes:

1. Reclassification of cost to align jurisdiction gas cost revenue with gas cost expense

2. Prior to 2009 Depreciation for all TGS jurisdictions was recorded to division office rather than local jurisdiction cost centers. Since book depreciation is entirely reversed and replaced with tax depreciation, no reclassification of book depreciation was made above. Instead, book depreciation is reversed from the cost center group to which it was actually recorded

3. Allocation of Shared Costs to Service Area	Alloc to Central	Total Alloc to Central Tx
Allocable Shared Service Costs	913,796,098	
Central Customers as of 6/30/2019	263,781	
Total TGS Customers as of 6/30/2019	663,330	
Allocation Factor	39.7662%	39.7662%
	363,381,984	363,381,984

4 - "Tax Depreciation" represents all book vs. tax plant-related timing differences including the excess of tax depreciation (including tax bonus depreciation) over book depreciation; amounts expensed per tax as repairs expense but but capitalized as additions per book; cost of removal deducted as expense per tax but taken to accumulated depreciation per book; the impact of any write off to expense of the net book value for tax purposes at the time of retirement, and CIAC credits taxed as income when received for tax purposes but deducted from plant basis per book.

5. If the NOL ADIT adjustment is a credit amount (negative amount), the carryforward to the summary ADFIT page will be zero since that means that there is net taxable income rather than a tax NOL (net operating loss).

6. If adding the NOL to the jurisdiction's other ADFIT components results in a net ADFIT debit, only add in only enough of the NOL above to bring the total net ADFIT for the jurisdiction to $0.

TGS Division Assets
Estimated Accumulated Deferred Income Tax Analysis
As of September 30, 2019

A	B	C (1010 & 1060) **Book Basis**	D (1080100 & 1110) **Book Reserve**	E **Net Book Basis**	G (1010 & 1060) **Tax Basis**	H (1080100 & 1110) **Tax Reserve**	I **Net Tax Basis**	K **Timing Difference**	L **TOTAL ADIT Asset/(Liability) (incl. Excess ADIT) 09/30/2019** 21% tax rate
TGS Division unadjusted		4,884,925	(342,878)	4,542,047	5,403,028	(4,162,266)	1,240,762	3,301,286	(693,270)
Adjustments									
301	Organization Costs	(127,437)	127,437	-	(104,835)		(104,835)	104,835	(22,015)
303	Intangible Property	(278,560)	278,560	-	(229,154)		(229,154)	229,154	(48,122)
376	Mains	-		-			-	-	-
389	Land & Land Rights	527,777		527,777	527,777		527,777	-	-
390.1	Structures & Improvements	2,907,882	(5,304)	2,902,578	2,907,882		2,907,882	(5,304)	1,114
390.2	Leasehold Equipment	(43,351)	43,745	394	(43,351)		(43,351)	43,745	(9,186)
390.21	Leasehold Equipment EOL			-			-	-	-
391.1	Office Furniture & Fixtures	-	(48,803)	(48,803)	-	-	-	(48,803)	10,249
391.2	Data Processing Equipment			-			-	-	-
391.2	Radio Towers			-			-	-	-
391.3	Office Machines			-			-	-	-
391.4	Audio Visual Equipment			-			-	-	-
391.5	Artwork			-			-	-	-
391.6	Purchased Software			-	-		-	-	-
391.9	Micro Computer Equipment	(11,143)	(2,992,047)	(3,003,190)	(6,475)	5,407	(1,068)	(3,002,122)	630,446
392.2	Pickup Trucks and Vans			-			-	-	-
392.3	Trucks 3/4 to 3 Ton			-			-	-	-
392.5	Trailers			-			-	-	-
392.6	Aircraft			-			-	-	-
394	Tools	(262)	(1,108)	(1,370)	(131)	91	(40)	(1,330)	279
394.2	Shop Equipment			-			-	-	-
397	Communication Equipment	-	(24,615)	(24,615)			-	(24,615)	5,169
398	Miscellaneous Equipment		-	-			-	-	-
Total Adjustments		2,974,907	(2,622,136)	352,771	3,051,713	5,498	3,057,211	(2,704,441)	567,934
TGS Division Adjusted		7,859,832	(2,965,014)	4,894,818	8,454,741	(4,156,768)	4,297,973	596,845	(125,336)
CTGCSA Allocation Factor		39.7662%	39.7662%	39.7662%	39.7662%	39.7662%	39.7662%	39.7662%	39.7662%
Total Division Allocated to CTGCSA		3,125,557	(1,179,073)	1,946,483	3,362,129	(1,652,989)	1,709,141	237,343	(49,841)

	C	D
Per WKP C.b.1 Post Test Year Div	4,423,681	
Per WKP C-1.b.1 Post Test Yr Div	3,436,151	
Per WKP D.b.1 Post Test Yr Div		(2,965,014)
	7,859,832	(2,965,014)
Difference	(0)	-

Service Area's % of customers: 39.7662%
(Input jurisdiction's factor on version pasted to juridictional ADIT file)

Service Area's allocated piece of ADFIT: (49,841)

ONEGAS, Inc. (Corporate Assets)
Estimated Accumulated Deferred Income Tax Analysis
As of Sept 30, 2019

Plant Acct	Description	A (1010 & 1060) Book Basis	B (1080100 & 1110) Book Reserve	Net Book Basis	C (1010 & 1060) Gross Tax Basis	D (1080100 & 1110) Tax Reserve	Net Tax Basis	Total Timing Difference	Estimated ADIT Asset/(Liability) 9/30/2019 (21% tax rate)	Allocation Factor to TGS	Timing Diff Allocated to TGS Divison	Deferred Tax Allocated to TGS Divison
	Total ONEGAS unadjusted	241,036,494.14	(75,362,258.66)	165,674,235	162,825,248	(114,947,039)	47,878,208	117,796,027	(24,737,166)			
389	Land & Land Rights	-	-	-	-	-	-	-	-	25.01%	-	-
391.1	Office Furniture & Equipment	255,010.17	(1,415.66)	253,595	255,011	(4,336)	250,674	2,920	(613)	25.01%	730	(153)
390.2	Leasehold Improvements	5,382,079.48	(2,133,609.48)	3,248,470	4,085,993	(582,723)	3,503,270	(254,800)	53,508	25.01%	(63,725)	13,382
391.1	Office Furniture & Equipment	3,605,934.31	(858,752.83)	2,747,181	433,067	(15,930)	417,138	2,330,044	(489,309)	25.01%	582,744	(122,376)
390.19	Airplane Hanger Furniture	11,869.56	(3,388.12)	8,481	-	-	-	8,481	(1,781)	25.01%	2,121	(445)
391.3	Office Machines	36,236.76	(14,326.54)	21,910	15,646	(567,812)	(552,165)	574,075	(120,556)	25.01%	143,576	(30,151)
391.4	Audio Visual Equipment	1,402,299.01	(1,090,137.83)	312,161	755,768	(665,652)	90,115	222,046	(46,630)	25.01%	55,534	(11,662)
391.5	Artwork	49,413.97	(10,635.21)	38,779	-	-	-	38,779	(8,144)	25.01%	9,699	(2,037)
391.6	Purchased Software	117,635,422.55	(27,642,554.79)	89,992,868	58,416,474	(25,102,761)	33,313,713	56,679,154	(11,902,622)	25.01%	14,175,457	(2,976,846)
391.6	Banner Software	5,471,958.05	(1,292,481.60)	4,179,476	12,465,023	(13,493,271)	(1,028,248)	5,207,724	(1,093,622)	30.41%	1,583,673	(332,571)
391.6	PowerPlant	870,000.01	(361,608.25)	508,392	870,000	(356,874)	513,126	(4,734)	994	24.02%	(1,137)	239
391.6	Maximo	3,117,560.99	(2,253,129.05)	864,432	3,117,561	(3,357,301)	(239,740)	1,104,172	(231,876)	24.71%	272,826	(57,293)
391.6	Concur Project	47,647.71	(47,647.71)	-	47,648	(47,648)	-	-	-	27.95%	-	-
391.6	Journey- Employee - ODC Distrigas	69,580,939.55	(26,272,810.56)	43,308,129	38,295,750	(33,222,433)	5,073,317	38,234,812	(8,029,311)	25.01%	9,562,527	(2,008,131)
391.6	Journey - Employee Count	1,848,836.03	(833,622.36)	1,015,214	-	-	-	1,015,214	(213,195)	27.95%	283,752	(59,588)
391.6	Ariba Software	-	-	-	-	-	-	-	-	30.96%	-	-
391.6	Ariba Software	903,328.29	(141,533.60)	761,795			-	761,795	(159,977)	30.96%	235,852	(49,529)
391.8	Micro Computer Equipment	16,975,889.07	(4,466,695.70)	12,509,193	10,434,136	(3,949,873)	6,484,263	6,024,930	(1,265,235)	25.01%	1,506,835	(316,435)
391.81	Aircraft Computer Equipment	130,857.17	(82,058.30)	48,799			-	48,799	(10,248)	25.01%	12,205	(2,563)
392.6	Aircraft	13,608,722.55	(7,845,188.51)	5,763,534	13,541,078	(13,515,102)	25,976	5,737,558	(1,204,887)	25.01%	1,434,963	(301,342)
397	Communicaton Equipment	102,488.60	(10,662.56)	91,826	20,092,094	(20,065,323)	26,771	65,055	(13,662)	25.01%	16,270	(3,417)
	Total ONEGAS unadjusted	241,036,493.83	(75,362,258.66)	165,674,235.17	162,825,248.21	(114,947,039.00)	47,878,209.21	117,796,025.96	(24,737,166.00)		29,813,901	(6,260,919)
		(0)	-	0	(0)	0	(1)	1	-			
Adjustments												
389	Land & Land Rights	-	-	-	-	-	-	-	-	25.01%	-	-
390.2	Leasehold Improvements	(52.09)		(52)	(52)	3	(49)	(3)	1	25.01%	(1)	0
390.19	Airplane Hanger Furniture	(11,869.56)	3,388.12	(8,481)	-	-	-	(8,481)	1,781	25.01%	(2,121)	445
391.5	Artwork	(49,413.97)	10,635.21	(38,779)	-	-	-	(38,779)	8,144	25.01%	(9,699)	2,037
391.6	Banner Software	(355.00)		(355)	(178)	-	(178)	(178)	37	30.41%	(54)	11
391.6	Purchased Software	(157,783.28)	56,619.44	(101,164)	(78,892)	65,743	(13,149)	(88,015)	18,483	25.01%	(22,013)	4,623
391.6	Journey- Employee - ODC Distrigas	(12,655.29)		(12,655)	(6,328)	-	(6,328)	(6,328)	1,329	25.01%	(1,583)	332
391.8	Micro Computer Equipment	(280.25)	-	(280)	(140)	-	(140)	(140)	29	25.01%	(35)	7
391.81	Aircraft Computer Equipment	(130,857.17)	82,058.30	(48,799)	(65,429)	65,426	(3)	(48,796)	10,247	25.01%	(12,204)	2,563
392.6	Aircraft	(13,608,722.55)	7,845,188.51	(5,763,534)	(13,541,078)	13,515,102	(25,976)	(5,737,558)	1,204,887	25.01%	(1,434,963)	301,342
397.2	Communicaton Equipment		-	-	-	-	-	-	-	25.01%	-	-
	Subtotal Adjustments	(13,971,989.16)	7,997,889.58	(5,974,099.58)	(13,692,095.36)	13,646,273.80	(45,821.55)	(5,928,278.03)	1,244,938.00		(1,482,672)	311,361
	Total Adjusted	227,064,504.67	(67,364,369.08)	159,700,135.59	149,133,152.86	(101,300,765.20)	47,832,387.66	111,867,747.93	(23,492,228.00)		28,331,229	(5,949,558)
				-					1			

Plant Acct	Description	(1010 & 1060) Book Basis Allocated to TGS	(1080100 & 1110) Book Reserve Allocated to TGS	Net Book Basis Allocated to TGS		(1010 & 1060) Gross Tax Basis Allocated to TGS	(1080100 & 1110) Tax Reserve Allocated to TGS	Net Tax Basis Allocated to TGS	Total Allocated Timing Difference	Allocated TOTAL ADIT Asset/(Liability) (incl. Excess ADIT) 9/30/2019 (21% tax rate)
	Total ONEGAS unadjusted	60,670,169	(18,941,838)	41,728,332		41,379,064	(29,464,633)	11,914,431	29,813,901	(6,260,919)
389	Land & Land Rights	-	-	-		-	-	-	-	-
391.1	Office Furniture & Equipment	63,778	(354)	63,424		63,778	(1,085)	62,694	730	(153)
390.2	Leasehold Improvements	1,346,058	(533,616)	812,442		1,021,907	(145,739)	876,168	(63,725)	13,382
391.1	Office Furniture & Equipment	901,844	(214,774)	687,070		108,310	(3,984)	104,326	582,744	(122,376)
390.19	Airplane Hanger Furniture	2,969	(847)	2,121		-	-	-	2,121	(445)
391.3	Office Machines	9,063	(3,583)	5,480		3,913	(142,010)	(138,096)	143,576	(30,151)
391.4	Audio Visual Equipment	350,715	(272,643)	78,072		189,017	(166,480)	22,538	55,534	(11,662)
391.5	Artwork	12,358	(2,660)	9,699		-	-	-	9,699	(2,037)
391.6	Purchased Software	29,420,619	(6,913,403)	22,507,216		14,609,960	(6,278,200)	8,331,760	14,175,457	(2,976,846)
391.6	Banner Software	1,664,027	(393,045)	1,270,982		3,790,623	(4,103,314)	(312,691)	1,583,673	(332,571)
391.6	PowerPlant	208,931	(86,840)	122,090		208,931	(85,703)	123,227	(1,137)	239
391.6	Maximo	770,306	(556,717)	213,589		770,306	(829,543)	(59,237)	272,826	(57,293)
391.6	Concur Project	13,317	(13,317)	-		13,317	(13,317)	-	-	-
391.6	Journey- Employee - ODC Distrigas	17,402,193	(6,570,830)	10,831,363		9,577,767	(8,308,931)	1,268,837	9,562,527	(2,008,131)
391.6	Journey - Employee Count	516,750	(232,997)	283,752		-	-	-	283,752	(59,588)
391.6	Ariba Software	-	-	-		-	-	-	-	-
391.6	Ariba Software	279,670	(43,819)	235,852		-	-	-	235,852	(49,529)
391.8	Micro Computer Equipment	4,245,670	(1,117,121)	3,128,549		2,609,577	(987,863)	1,621,714	1,506,835	(316,435)
391.81	Aircraft Computer Equipment	32,727	(20,523)	12,205		-	-	-	12,205	(2,563)
392.6	Aircraft	3,403,542	(1,962,082)	1,441,460		3,386,624	(3,380,127)	6,496	1,434,963	(301,342)
397	Communicaton Equipment	25,632	(2,667)	22,966		5,025,033	(5,018,337)	6,695	16,270	(3,417)
	Total ONEGAS unadjusted	60,670,169	(18,941,838)	41,728,332		41,379,064	(29,464,633)	11,914,431	29,813,901	(6,260,919)
Adjustments										
389	Land & Land Rights	-	-	-		-	-	-	-	-
390.2	Leasehold Improvements	(13)	-	(13)		(13)	1	(12)	(1)	0
390.19	Airplane Hanger Furniture	(2,969)	847	(2,121)		-	-	-	(2,121)	445
391.5	Artwork	(12,358)	2,660	(9,699)		-	-	-	(9,699)	2,037
391.6	Banner Software	(108)	-	(108)		(54)	-	(54)	(54)	11
391.6	Purchased Software	(39,462)	14,161	(25,301)		(19,731)	16,442	(3,288)	(22,013)	4,623
391.6	Journey- Employee - ODC Distrigas	(3,165)	-	(3,165)		(1,583)	-	(1,583)	(1,583)	332
391.8	Micro Computer Equipment	(70)	-	(70)		(35)	-	(35)	(35)	7
391.81	Aircraft Computer Equipment	(32,727)	20,523	(12,205)		(16,364)	16,363	(1)	(12,204)	2,563
392.6	Aircraft	(3,403,542)	1,962,082	(1,441,460)		(3,386,624)	3,380,127	(6,496)	(1,434,963)	301,342
397.2	Communicaton Equipment	-	-	-		-	-	-	-	-
	Subtotal Adjustments	(3,494,414)	2,000,272	(1,494,141)		(3,424,403)	3,412,933	(11,470)	(1,482,672)	311,361
	Total Adjusted	57,175,756	(16,941,566)	40,234,190	(A)	37,954,661	(26,051,700)	11,902,961	28,331,229	(5,949,558)
	Service Area's % of customers	39.7662%	39.7662%	39.7662%		39.7662%	39.7662%	39.7662%	39.7662%	39.7662%
		22,736,625	(6,737,017)	15,999,609		15,093,127	(10,359,771)	4,733,355	11,266,253	(2,365,913)

Service Area's % of customers 39.7662%
(Input jurisdiction's factor on version pasted to juridictional ADIT file)

Service Area's allocated piece of ADFIT on plant (2,365,913)

	Book Basis Allocated to TGS	Book Reserve Allocated to TGS
Per WKP C.c Corp Plant	48,700,525	
Per WKP C-1.c Corp CCNC	8,475,214	
Per WKP D.c Corp Reserves		(16,941,570)
	57,175,739	(16,941,570)
Difference (immaterial/rounding)	16.62	4.01

	A	B	C	D	E	F	G	H	I	J	K	L
1												
2	**Calculation of ADIT re CTSA Repair Adjustment**											
3												
4												
5		**Per Tax Report 30:**										
6		2008 Tax Repair Blankets	2008 Tax Repair Bonus	2008 Tax Repair Bonus Depr Adju	2008 Tax Repair Expense	2009 Tax Repair Blankets	2009 Tax Repair Bonus	2009 Tax Repair Bonus Depr Adju	2009 Tax Repair Expense	Tax Expensing (2010-2018 Tax Repair)	Total Tax Repairs Adjustment	ADIT Asset/(Liability) at 21%
7												
8	Buda	-	-	-	-	-	-	-	-	-	-	-
9	Central Texas	(5,041,909)	2,802,776	2,756,907	(4,548,007)	(1,346,554)	680,764	777,787	(3,453,716)	(57,218,049)	(64,590,001)	(13,563,900)
10	Kyle	-	-	549	(1,134)	-	-	-	(1,624)	(114)	(2,323)	(488)
11	Nixon	-	-	-	-	(2,462)	1,231		-	(72,894)	(74,124)	(15,566)
12	South Texas	(208,536)	84,461	339,760	(911,994)	(166,486)	89,011	229,509	(590,342)	(5,459,225)	(6,593,842)	(1,384,707)
13	Total Central Texas Area	(5,250,445)	2,887,237	3,097,217	(5,461,135)	(1,515,503)	771,006	1,007,296	(4,045,682)	(62,750,282)	(71,260,291)	(14,964,661)
14												
15												
16												
17												
18												

Texas Gas Service Company, a Division of ONE Gas, Inc.
CGSA ISOS RTCS TYE June 30, 2019
Updated for Known and Measurable Changes Through September 30, 2019

	A	B	C	D	E	F	G	H	I
1	**ARAM Estimate for amounts attributed TO the CTX SERVICE AREA**								
2	**For case filed with Year Ended 9.30.2019**								
3									
4									
5									
6	**Accumulated Deferred Income Taxes for:**	**Excess ADIT**		**Protected**	**Unprotected**		**TGS Amortization Amount**	**ONE Gas Amortization Amount**	**2018 Amortization**
7	**Central Texas Direct Plant Assets Depreciation**	(28,694,365)		$ (28,694,365)			$ (28,694,365)		$ 263,234
8	**Central Texas Direct Plant Repairs**	(8,319,002)			(8,319,002)		$ (8,319,002)		751,462
9	**Central Texas Other Rate Base Items**	(2,676,419)			(2,676,419)		$ (2,676,419)		267,642
10	**TGS Division Plant Assets Depreciation**	(225,312)		(225,312)			(225,312)		$ 55,752
11	**ONEGas Plant Assets Depreciation**	(1,308,791)		(1,308,791)				$ (1,308,791)	$ 157,735
12	**Central Texas NOL (See NOL tab, Note 6)**	19,296,333		19,296,333	-		19,296,333		(499,204)
13				$ -			$ -		
14	**ADIT - Accumulated Deferred Income Taxes**	(21,927,556)		(10,932,135)	(10,995,421)		(20,618,765)	(1,308,791)	996,621
15									
16	Percent Protected			50%					
17	**CTX without Grossup**								
18		TGS Amortization	ONE Gas Amortization	TGS NOL	OGS NOL		Total Amortization		
19	Year 1 - 2018 Actuals	$ 1,338,090	$ 157,735	$ (499,204)	$ 499,204		$ 996,621		
20									

	A	B	C	D	E	F	G	H	I	J	K	L
1		**Rate Filing**	**Sum of Beg APB11 DIT**	**Sum of End APB11 DIT**	**Sum of Beg Timing Diff**	**Sum of End Timing Diff**	**Sum of APB11 DIT Provision**	**Sum of APB11 DIT Reversal**	**Sum of Beg FAS109 DIT**	**Sum of Beg Reg Liab Pre Grossup**	**Sum of Reg Liability Reversal**	
2	2017		**80,483,030**	**91,045,909**	**229,951,515**	**260,131,169**			**91,045,909**	**(36,418,363)**		
3	2018		91,045,909	92,163,767	260,131,169	270,286,189	3,156,131	(2,038,273)	92,163,767	**(35,403,667)**	1,014,696	2.786%

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PowerTax Deferred Tax Summary Report

2018 AS FILED Tax Return FINAL
091 Texas Gas Service

Grouped By: Total Tax Classes

Jurisdiction: Federal Rate Cas Tax Year: 2018	Beginning Difference	Current Difference	Ending Difference	Beginning APB11 DFIT Balance	Current DFIT	Ending APB11 DFIT Balance	End FAS109 Liability @ Stat Rate	Regulatory Asset Before Gross-Up	Regulatory Liab Before Gross-Up	Regulatory Asset After Gross-Up	Regulatory Liab After Gross-Up
TGS Fed RC M/L	$206,455,313.79	$9,340,591.89	$215,795,905.68	$72,259,359.72	$1,698,290.08	$73,957,649.80	$45,317,140.19	($0.00)	($28,640,509.60)	($0.00)	($36,253,809.62)
Depreciation Difference	**$206,455,313.79**	**$9,340,591.89**	**$215,795,905.68**	**$72,259,359.72**	**$1,698,290.08**	**$73,957,649.80**	**$45,317,140.19**	**($0.00)**	**($28,640,509.60)**	**($0.00)**	**($36,253,809.62)**
Federal Rate Case Amortization	$0.00	$0.01	$0.01	$7,514,619.59	($751,461.98)	$6,763,157.61	$0.00	$0.00	($6,763,157.61)	$0.00	($6,763,157.61)
Depreciation Difference	**$0.00**	**$0.01**	**$0.01**	**$7,514,619.59**	**($751,461.98)**	**$6,763,157.61**	**$0.00**	**$0.00**	**($6,763,157.61)**	**$0.00**	**($6,763,157.61)**
TGS Fed RC 2008 Tax Rep Blank 4	$3,810,653.75	($117,392.55)	$3,693,261.20	$800,237.28	($24,652.43)	$775,584.85	$775,584.85	$0.00	$0.00	$0.00	$0.00
TGS Fed RC 2008 Tax Rep Exp 48	$3,421,171.91	($125,102.06)	$3,296,069.85	$718,446.10	($26,271.44)	$692,174.66	$692,174.67	$0.03	($0.02)	$0.03	($0.02)
TGS Fed RC 2009 Tax Rep Blank 4	$1,143,702.47	($34,326.86)	$1,109,375.61	$240,177.52	($7,208.64)	$232,968.88	$232,968.88	($0.01)	$0.01	($0.01)	$0.01
TGS Fed RC 2009 Tax Rep Exp 48	$2,857,575.44	($92,286.27)	$2,765,289.17	$600,090.86	($19,380.12)	$580,710.74	$580,710.73	($0.01)	($0.01)	($0.01)	($0.01)
TGS Fed RC Tax Expensing	$46,326,837.78	$10,554,761.25	$56,881,599.03	$9,728,635.98	$2,216,499.87	$11,945,135.85	$11,945,135.80	$0.09	($0.15)	$0.12	($0.19)
Book Overhead	**$57,559,941.35**	**$10,185,653.51**	**$67,745,594.86**	**$12,087,587.74**	**$2,138,987.24**	**$14,226,574.98**	**$14,226,574.92**	**$0.11**	**($0.16)**	**$0.13**	**($0.21)**
TGS Fed RC 2008 Tax Rep Bonus	($794,182.46)	$139,440.72	($654,741.74)	($166,778.33)	$29,282.55	($137,495.78)	($137,495.77)	($0.00)	$0.02	($0.00)	$0.02
TGS Fed RC 2008 Tax Rep Bonus-	($966,698.03)	$169,272.56	($797,425.47)	($203,006.59)	$35,547.24	($167,459.35)	($167,459.35)	$0.00	$0.00	$0.00	$0.00
TGS Fed RC 2009 Tax Rep Bonus	($596,123.37)	$54,878.54	($541,244.83)	($125,185.92)	$11,524.51	($113,661.41)	($113,661.41)	$0.01	($0.01)	$0.01	($0.01)
TGS Fed RC 2009 Tax Rep Bonus-	($689,230.16)	$45,527.92	($643,702.24)	($144,738.34)	$9,560.87	($135,177.47)	($135,177.47)	$0.00	($0.00)	$0.00	($0.00)
TGS Fed RC 8.209 ROE	($2,283,807.12)	($506,179.61)	($2,789,986.73)	($479,599.51)	($106,297.74)	($585,897.25)	($585,897.21)	($0.01)	$0.05	($0.02)	$0.06
TGS Fed RC Book-Tax Difference	$1,095,154.54	($456,502.38)	$638,652.16	$229,982.45	($95,865.50)	$134,116.95	$134,116.95	$0.01	($0.00)	$0.01	($0.00)
TGS Fed RC CIAC	($14,248,227.20)	($5,425,782.92)	($19,674,010.12)	($2,992,127.73)	($1,139,414.35)	($4,131,542.08)	($4,131,542.13)	($0.15)	$0.10	($0.19)	$0.13
TGS Fed RC Fed RC Only B/T Diff	$1,993,168.91	($1,055,934.28)	$937,234.63	$418,565.49	($221,746.16)	$196,819.33	$196,819.27	$0.01	($0.07)	$0.02	($0.09)
TGS Fed RC Non-Fed/State B/T Di	$12,605,859.03	($2,335,946.39)	$10,269,912.64	$2,647,230.42	($490,548.72)	$2,156,681.70	$2,156,681.65	$0.03	($0.07)	$0.03	($0.09)
Tax Overhead	**($3,884,085.86)**	**($9,371,225.84)**	**($13,255,311.70)**	**($815,658.06)**	**($1,967,957.30)**	**($2,783,615.36)**	**($2,783,615.46)**	**($0.11)**	**$0.02**	**($0.14)**	**$0.02**
Total Tax Classes	**$260,131,169.28**	**$10,155,019.57**	**$270,286,188.85**	**$91,045,908.99**	**$1,117,858.04**	**$92,163,767.03**	**$56,760,099.66**	**($0.01)**	**($35,403,667.36)**	**($0.01)**	**($43,016,967.42)**
Jurisdiction Totals:	**$260,131,169.28**	**$10,155,019.57**	**$270,286,188.85**	**$91,045,908.99**	**$1,117,858.04**	**$92,163,767.03**	**$56,760,099.66**	**($0.01)**	**($35,403,667.36)**	**($0.01)**	**($43,016,967.42)**
Company Totals:	**$260,131,169.28**	**$10,155,019.57**	**$270,286,188.85**	**$91,045,908.99**	**$1,117,858.04**	**$92,163,767.03**	**$56,760,099.66**	**($0.01)**	**($35,403,667.36)**	**($0.01)**	**($43,016,967.42)**

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2018 AS FILED Tax Return FINAL
091 Texas Gas Service
PowerTax Deferred Tax Summary Report
Grouped By: Total Tax Classes

Jurisdiction : Federal Rate Case Tax Year : 2018	Beginning Difference	Provision	Reversal	Ending Difference	Beginning DFIT Balance	Current DFIT Provision	Current DFIT Reversal	Deferred Trans/Adj	Ending DFIT Balance
TGS Fed RC 2008 Tax Rep Blank 481a	$3,810,653.75	$0.00	($117,392.55)	$3,693,261.20	$800,237.28	$0.00	($24,652.43)	$0.00	$775,584.85
TGS Fed RC 2008 Tax Rep Exp 481a	$3,421,171.91	$0.00	($125,102.06)	$3,296,069.85	$718,446.10	$0.00	($26,271.44)	$0.00	$692,174.66
TGS Fed RC 2009 Tax Rep Blank 481a	$1,143,702.47	$0.00	($34,326.86)	$1,109,375.61	$240,177.52	$0.00	($7,208.64)	$0.00	$232,968.88
TGS Fed RC 2009 Tax Rep Exp 481a	$2,857,575.44	$0.00	($92,286.27)	$2,765,289.17	$600,090.86	$0.00	($19,380.12)	$0.00	$580,710.74
TGS Fed RC Tax Expensing	$46,326,837.78	$11,881,110.29	($1,326,349.04)	$56,881,599.03	$9,728,635.98	$2,495,033.15	($278,533.32)	$0.00	$11,945,135.85
Total Tax Classes	**$57,559,941.35**	**$11,881,110.29**	**($1,695,456.78)**	**$67,745,594.86**	**$12,087,587.74**	**$2,495,033.15**	**($356,045.95)**	**$0.00**	**$14,226,574.98**
Amortization Type Book Overhead Totals:	**$57,559,941.35**	**$11,881,110.29**	**($1,695,456.78)**	**$67,745,594.86**	**$12,087,587.74**	**$2,495,033.15**	**($356,045.95)**	**$0.00**	**$14,226,574.98**
Federal Rate Case Amortization	$0.00	$0.00	$0.01	$0.01	$7,514,619.59	$0.00	($751,461.98)	$0.00	$6,763,157.61
TGS Fed RC M/L	$206,455,313.79	$11,220,835.86	($1,880,243.97)	$215,795,905.68	$72,259,359.72	$2,356,375.53	($658,085.46)	$0.00	$73,957,649.80
Total Tax Classes	**$206,455,313.79**	**$11,220,835.86**	**($1,880,243.96)**	**$215,795,905.69**	**$79,773,979.31**	**$2,356,375.53**	**($1,409,547.44)**	**$0.00**	**$80,720,807.41**
Amortization Type Depreciation Difference Totals:	**$206,455,313.79**	**$11,220,835.86**	**($1,880,243.96)**	**$215,795,905.69**	**$79,773,979.31**	**$2,356,375.53**	**($1,409,547.44)**	**$0.00**	**$80,720,807.41**
TGS Fed RC 2008 Tax Rep Bonus Depr	($794,182.46)	$0.00	$139,440.72	($654,741.74)	($166,778.33)	$0.00	$29,282.55	$0.00	($137,495.78)
TGS Fed RC 2008 Tax Rep Bonus-Blank	($966,698.03)	$0.00	$169,272.56	($797,425.47)	($203,006.59)	$0.00	$35,547.24	$0.00	($167,459.35)
TGS Fed RC 2009 Tax Rep Bonus Depr	($596,123.37)	$0.00	$54,878.54	($541,244.83)	($125,185.92)	$0.00	$11,524.51	$0.00	($113,661.41)
TGS Fed RC 2009 Tax Rep Bonus-Blank	($689,230.16)	$0.00	$45,527.92	($643,702.24)	($144,738.34)	$0.00	$9,560.87	$0.00	($135,177.47)
TGS Fed RC 8.209 ROE	($2,283,807.12)	($718,113.14)	$211,933.53	($2,789,986.73)	($479,599.51)	($150,803.76)	$44,506.03	$0.00	($585,897.25)
TGS Fed RC Book-Tax Difference	$1,095,154.54	$0.00	($456,502.38)	$638,652.16	$229,982.45	$0.00	($95,865.50)	$0.00	$134,116.95
TGS Fed RC CIAC	($14,248,227.20)	($7,354,639.25)	$1,928,856.33	($19,674,010.12)	($2,992,127.73)	($1,544,474.24)	$405,059.90	$0.00	($4,131,542.08)
TGS Fed RC Fed RC Only B/T Diff	$1,993,168.91	$0.00	($1,055,934.28)	$937,234.63	$418,565.49	$0.00	($221,746.16)	$0.00	$196,819.33
TGS Fed RC Non-Fed/State B/T Diff	$12,605,859.03	$0.00	($2,335,946.39)	$10,269,912.64	$2,647,230.42	$0.00	($490,548.72)	$0.00	$2,156,681.70
Total Tax Classes	**($3,884,085.86)**	**($8,072,752.39)**	**($1,298,473.45)**	**($13,255,311.70)**	**($815,658.06)**	**($1,695,278.00)**	**($272,679.28)**	**$0.00**	**($2,783,615.36)**
Amortization Type Tax Overhead Totals:	**($3,884,085.86)**	**($8,072,752.39)**	**($1,298,473.45)**	**($13,255,311.70)**	**($815,658.06)**	**($1,695,278.00)**	**($272,679.28)**	**$0.00**	**($2,783,615.36)**
Jurisdiction Totals:	**$260,131,169.28**	**$15,029,193.76**	**($4,874,174.19)**	**$270,286,188.85**	**$91,045,908.99**	**$3,156,130.68**	**($2,038,272.67)**	**$0.00**	**$92,163,767.03**
Company Totals:	**$260,131,169.28**	**$15,029,193.76**	**($4,874,174.19)**	**$270,286,188.85**	**$91,045,908.99**	**$3,156,130.68**	**($2,038,272.67)**	**$0.00**	**$92,163,767.03**

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PowerTax Deferred Tax Summary Report

2017 AS FILED ARAM
091 Texas Gas Service

Grouped By: Total Tax Classes

Jurisdiction: Federal Rate Cas Tax Year: 2017	Beginning Difference	Current Difference	Ending Difference	Beginning APB11 DFIT Balance	Current DFIT	Ending APB11 DFIT Balance	End FAS109 Liability @ Stat Rate	Regulatory Asset Before Gross-Up	Regulatory Liab Before Gross-Up	Regulatory Asset After Gross-Up	Regulatory Liab After Gross-Up
TGS Fed RC M/L	$178,885,524.40	$27,569,789.39	$206,455,313.79	$62,609,933.57	$9,649,426.15	$72,259,359.72	$72,259,359.83	$0.61	($0.50)	$0.93	($0.77)
Depreciation Difference	**$178,885,524.40**	**$27,569,789.39**	**$206,455,313.79**	**$62,609,933.57**	**$9,649,426.15**	**$72,259,359.72**	**$72,259,359.83**	**$0.61**	**($0.50)**	**$0.93**	**($0.77)**
TGS Fed RC 2008 Tax Rep Blank 4	$3,924,340.26	($113,686.51)	$3,810,653.75	$1,373,519.08	($39,790.27)	$1,333,728.81	$1,333,728.81	($0.00)	$0.00	($0.00)	$0.01
TGS Fed RC 2008 Tax Rep Exp 48	$3,543,082.89	($121,910.98)	$3,421,171.91	$1,240,079.02	($42,668.83)	$1,197,410.19	$1,197,410.17	$0.02	($0.04)	$0.03	($0.06)
TGS Fed RC 2009 Tax Rep Blank 4	$1,177,040.35	($33,337.88)	$1,143,702.47	$411,964.12	($11,668.27)	$400,295.85	$400,295.86	$0.01	$0.01	$0.01	$0.01
TGS Fed RC 2009 Tax Rep Exp 48	$2,947,293.73	($89,718.29)	$2,857,575.44	$1,031,552.80	($31,401.38)	$1,000,151.42	$1,000,151.40	($0.00)	($0.01)	($0.01)	($0.02)
TGS Fed RC Tax Expensing	$38,991,065.59	$7,335,772.19	$46,326,837.78	$13,646,872.87	$2,567,520.26	$16,214,393.13	$16,214,393.22	$0.15	($0.05)	$0.22	($0.08)
Book Overhead	**$50,582,822.82**	**$6,977,118.53**	**$57,559,941.35**	**$17,703,987.89**	**$2,441,991.51**	**$20,145,979.40**	**$20,145,979.47**	**$0.17**	**($0.09)**	**$0.26**	**($0.14)**
TGS Fed RC 2008 Tax Rep Bonus	($934,250.78)	$140,068.32	($794,182.46)	($326,987.78)	$49,023.92	($277,963.86)	($277,963.86)	($0.02)	$0.02	($0.03)	$0.03
TGS Fed RC 2008 Tax Rep Bonus-	($1,135,969.73)	$169,271.70	($966,698.03)	($397,589.41)	$59,245.09	($338,344.32)	($338,344.31)	$0.00	$0.01	$0.00	$0.01
TGS Fed RC 2009 Tax Rep Bonus	($650,997.14)	$54,873.77	($596,123.37)	($227,849.00)	$19,205.81	($208,643.19)	($208,643.18)	$0.00	$0.01	$0.01	$0.01
TGS Fed RC 2009 Tax Rep Bonus-	($734,759.11)	$45,528.95	($689,230.16)	($257,165.69)	$15,935.13	($241,230.56)	($241,230.56)	$0.00	$0.00	$0.00	$0.00
TGS Fed RC 8.209 ROE	($1,115,807.66)	($1,167,999.46)	($2,283,807.12)	($390,532.71)	($408,799.81)	($799,332.52)	($799,332.49)	$0.01	$0.02	$0.01	$0.04
TGS Fed RC Book-Tax Difference	$1,557,981.93	($462,827.39)	$1,095,154.54	$545,293.67	($161,989.59)	$383,304.08	$383,304.09	$0.01	$0.00	$0.01	$0.00
TGS Fed RC CIAC	($14,529,345.13)	$281,117.93	($14,248,227.20)	($5,085,270.73)	$98,391.24	($4,986,879.49)	($4,986,879.52)	($0.06)	$0.03	($0.10)	$0.05
TGS Fed RC Fed RC Only B/T Diff	$3,048,158.78	($1,054,989.87)	$1,993,168.91	$1,066,855.54	($369,246.47)	$697,609.07	$697,609.12	$0.03	$0.02	$0.04	$0.03
TGS Fed RC Non-Fed/State B/T Di	$14,978,156.83	($2,372,297.80)	$12,605,859.03	$5,242,354.89	($830,304.25)	$4,412,050.64	$4,412,050.66	$0.05	($0.03)	$0.07	($0.04)
Tax Overhead	**$483,167.99**	**($4,367,253.85)**	**($3,884,085.86)**	**$169,108.78**	**($1,528,538.93)**	**($1,359,430.15)**	**($1,359,430.05)**	**$0.01**	**$0.09**	**$0.01**	**$0.14**
Total Tax Classes	**$229,951,515.21**	**$30,179,654.07**	**$260,131,169.28**	**$80,483,030.24**	**$10,562,878.73**	**$91,045,908.97**	**$91,045,909.25**	**$0.78**	**($0.50)**	**$1.20**	**($0.77)**
Jurisdiction Totals:	**$229,951,515.21**	**$30,179,654.07**	**$260,131,169.28**	**$80,483,030.24**	**$10,562,878.73**	**$91,045,908.97**	**$91,045,909.25**	**$0.78**	**($0.50)**	**$1.20**	**($0.77)**
Company Totals:	**$229,951,515.21**	**$30,179,654.07**	**$260,131,169.28**	**$80,483,030.24**	**$10,562,878.73**	**$91,045,908.97**	**$91,045,909.25**	**$0.78**	**($0.50)**	**$1.20**	**($0.77)**

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2017 AS FILED ARAM
091 Texas Gas Service
PowerTax Deferred Tax Summary Report
Grouped By: Total Tax Classes

Jurisdiction : Federal Rate Case Tax Year : 2017	Beginning Difference	Provision	Reversal	Ending Difference	Beginning DFIT Balance	Current DFIT Provision	Current DFIT Reversal	Deferred Trans/Adj	Ending DFIT Balance
TGS Fed RC 2008 Tax Rep Blank 481a	$3,924,340.26	$0.00	($113,686.51)	$3,810,653.75	$1,373,519.08	$0.00	($39,790.27)	$0.00	$1,333,728.81
TGS Fed RC 2008 Tax Rep Exp 481a	$3,543,082.89	$0.00	($121,910.98)	$3,421,171.91	$1,240,079.02	$0.00	($42,668.83)	$0.00	$1,197,410.19
TGS Fed RC 2009 Tax Rep Blank 481a	$1,177,040.35	$0.00	($33,337.88)	$1,143,702.47	$411,964.12	$0.00	($11,668.27)	$0.00	$400,295.85
TGS Fed RC 2009 Tax Rep Exp 481a	$2,947,293.73	$0.00	($89,718.29)	$2,857,575.44	$1,031,552.80	$0.00	($31,401.38)	$0.00	$1,000,151.42
TGS Fed RC Tax Expensing	$38,991,065.59	$8,400,244.56	($1,064,472.37)	$46,326,837.78	$13,646,872.87	$2,940,085.58	($372,565.39)	$0.00	$16,214,393.13
Total Tax Classes	**$50,582,822.82**	**$8,400,244.56**	**($1,423,126.03)**	**$57,559,941.35**	**$17,703,987.89**	**$2,940,085.58**	**($498,094.14)**	**$0.00**	**$20,145,979.40**
Amortization Type Book Overhead Totals:	**$50,582,822.82**	**$8,400,244.56**	**($1,423,126.03)**	**$57,559,941.35**	**$17,703,987.89**	**$2,940,085.58**	**($498,094.14)**	**$0.00**	**$20,145,979.40**
TGS Fed RC M/L	$178,885,524.40	$29,162,099.60	($1,592,310.21)	$206,455,313.79	$62,609,933.57	$10,206,734.86	($557,308.76)	$0.00	$72,259,359.72
Total Tax Classes	**$178,885,524.40**	**$29,162,099.60**	**($1,592,310.21)**	**$206,455,313.79**	**$62,609,933.57**	**$10,206,734.86**	**($557,308.76)**	**$0.00**	**$72,259,359.72**
Amortization Type Depreciation Difference Totals:	**$178,885,524.40**	**$29,162,099.60**	**($1,592,310.21)**	**$206,455,313.79**	**$62,609,933.57**	**$10,206,734.86**	**($557,308.76)**	**$0.00**	**$72,259,359.72**
TGS Fed RC 2008 Tax Rep Bonus Depr	($934,250.78)	$0.00	$140,068.32	($794,182.46)	($326,987.78)	$0.00	$49,023.92	$0.00	($277,963.86)
TGS Fed RC 2008 Tax Rep Bonus-Blank	($1,135,969.73)	$0.00	$169,271.70	($966,698.03)	($397,589.41)	$0.00	$59,245.09	$0.00	($338,344.32)
TGS Fed RC 2009 Tax Rep Bonus Depr	($650,997.14)	$0.00	$54,873.77	($596,123.37)	($227,849.00)	$0.00	$19,205.81	$0.00	($208,643.19)
TGS Fed RC 2009 Tax Rep Bonus-Blank	($734,759.11)	$0.00	$45,528.95	($689,230.16)	($257,165.69)	$0.00	$15,935.13	$0.00	($241,230.56)
TGS Fed RC 8.209 ROE	($1,115,807.66)	($1,537,326.72)	$369,327.26	($2,283,807.12)	($390,532.71)	($538,064.34)	$129,264.54	$0.00	($799,332.52)
TGS Fed RC Book-Tax Difference	$1,557,981.93	$0.00	($462,827.39)	$1,095,154.54	$545,293.67	$0.00	($161,989.59)	$0.00	$383,304.08
TGS Fed RC CIAC	($14,529,345.13)	($1,670,593.93)	$1,951,711.86	($14,248,227.20)	($5,085,270.73)	($584,707.90)	$683,099.09	$0.00	($4,986,879.49)
TGS Fed RC Fed RC Only B/T Diff	$3,048,158.78	$0.00	($1,054,989.87)	$1,993,168.91	$1,066,855.54	$0.00	($369,246.47)	$0.00	$697,609.07
TGS Fed RC Non-Fed/State B/T Diff	$14,978,156.83	$0.00	($2,372,297.80)	$12,605,859.03	$5,242,354.89	$0.00	($830,304.25)	$0.00	$4,412,050.64
Total Tax Classes	**$483,167.99**	**($3,207,920.65)**	**($1,159,333.20)**	**($3,884,085.86)**	**$169,108.78**	**($1,122,772.24)**	**($405,766.73)**	**$0.00**	**($1,359,430.15)**
Amortization Type Tax Overhead Totals:	**$483,167.99**	**($3,207,920.65)**	**($1,159,333.20)**	**($3,884,085.86)**	**$169,108.78**	**($1,122,772.24)**	**($405,766.73)**	**$0.00**	**($1,359,430.15)**
Jurisdiction Totals:	**$229,951,515.21**	**$34,354,423.51**	**($4,174,769.44)**	**$260,131,169.28**	**$80,483,030.24**	**$12,024,048.20**	**($1,461,169.63)**	**$0.00**	**$91,045,908.97**
Company Totals:	**$229,951,515.21**	**$34,354,423.51**	**($4,174,769.44)**	**$260,131,169.28**	**$80,483,030.24**	**$12,024,048.20**	**($1,461,169.63)**	**$0.00**	**$91,045,908.97**

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Ready

Row	A	B	C	D
2	**SUMMARY ADIT ALLOCATIONS TO GULF COAST SERVICE AREA**			
3	**For General Rate Case - Test Year Ended 9/30/2019**			
5–7	**Estimated Accumulated Deferred Income Taxes for:**	**ADIT at 21%**	**Unamortized Excess ADIT - Bal at 9/30/2019**	**Total GCSA ADIT and Excess ADIT at 9/30/2019**
8	**Gulf Coast Service Area Plant Assets Depreciation**	(8,382,580)	(5,269,984)	(13,652,564)
9	**Gulf Coast Service Area Direct Plant Repairs**	(3,598,275)	(2,302,998)	(5,901,273)
10	**Subtotal GCSA Direct Plant Assets Depreciation**	(11,980,855)	(7,572,983)	(19,553,837)
11	**Gulf Coast Service Area Other Rate Base Items**	(740,456)	(459,628)	(1,200,084)
12	**TGS Division Plant Assets Depreciation**	(8,431)	(39,261)	(47,692)
13	**ONEGAS Plant Assets Depreciation**	(400,227)	(233,209)	(633,436)
14	**Gulf Coast Service Area NOL**	1,266,097	1,772,469	3,038,566
16	**ADFIT - Accumulated Deferred Federal Income Taxes**	(11,863,873)	(6,532,611)	(18,396,483)

20 Accumulated Deferred Income Tax - Gulf Coast Service Area Plant Related Items

Row	A	B	C	D	E	F	G	H	I
22–24	**As of Sept 30, 2019** / **Town**	**Gross Book Basis**	**Book Reserve**	**Net Book Basis**	**Gross Tax Basis**	**Tax Reserve**	**Net Tax Basis**	**Difference in Net Plant Basis**	**Estimated ADIT Asset/(Liability) at 21%**
25	Galveston	34,522,582	(11,348,593)	23,173,989	18,845,888	(12,044,309)	6,801,579		
26	South Jefferson	66,324,468	(15,626,628)	50,697,840	31,319,306	(20,538,695)	10,780,611		
27		100,847,050	(26,975,221)	73,871,828	50,165,194	(32,583,005)	17,582,190	56,289,639	(11,820,824)
29	Gulf Coast Service Area Direct Plant	100,847,050	(26,975,221)	73,871,828	50,165,194	(32,583,005)	17,582,190	56,289,639	(11,820,824)
30				-			-		
31	Gulf Coast 101 Retirement Adjustments	(1,046,273)		(1,046,273.00)					
32	Gulf Coast 108 Retirement Adjustments		1,046,273	1,046,273.00					
33	Gulf Coast 108 RWIP Adjustments		611,396	611,396.00					
34	Gulf Coast 101 Adjustments - Other	(521)		(520.74)					
35	Gulf Coast 106 Adjustments	380,477		380,476.94					
36	Gulf Coast 108/111 Adjustments - Other		193,838	193,838.39					
37	Subtotal Gulf Coast Adjustments	(666,316.80)	1,851,507.39	1,185,190.59	189,004.80	234,134.76	423,140	762,051	(160,031)
39	Subtotal Adjustments	(666,317)	1,851,507	1,185,191	189,005	234,135	423,140	762,051	(160,031)
41	**Adjusted Gulf Coast Service Area**	**100,180,733**	**(25,123,714)**	**75,057,019**	**50,354,199**	**(32,348,870)**	**18,005,329**	**57,051,690**	**(11,980,855)**
43	**TGS Division (Allocated to Gulf Coast Service Area)**	**528,731**	**(199,456)**	**329,274**	**568,750**	**(279,626)**	**289,125**	**40,150**	**(8,431)**
45	**ONEGas (Allocated to Gulf Coast Service Area)**	**3,846,213**	**(1,139,659)**	**2,706,554**	**2,553,210**	**(1,752,498)**	**800,712**	**1,905,842**	**(400,227)**

49 Accumulated Deferred Income Tax Analysis For Gulf Coast Service Area Other Rate Base Items

Row	A	B	C	D	E
51		**Balance Sheet Impact per Book**	**Balance Sheet Impact per Tax**	**Difference**	**Estimated ADIT Asset/(Liability)**
53	Pension/OPEB Expense Regulatory Deferrals	88,263	-	88,263	(18,535)
55	Prepaid Pension (funding in excess of FAS87 expense)	3,377,129	-	3,377,129	(709,197)
57	Section 8.209 Deferral	60,592	-	60,592	(12,724)
59	Total Other Rate Base Items				(740,456)

Summary of Gulf Coast Service Area NOL as of June 30, 2019 with Update to Sept 30, 201

Row	Line	Description	Notes	Division Office Cost Centers, Incl Corp Alloc	Gulf	Total Gulf Coast Service Area Including Allocated Amts
4				(a)	(c)	(d)
5						
6	1	Total Pre Tax Net (Income)/loss per Book thru June 2019		(1,565,071,987)	53,465,300	(51,817,092)
7						
8	2	Reclass Gas Cost between Jurisdictions and Division Office Cost Centers	1	2,604,525,522	(176,878,558)	(1,672,126)
9	3	Subtotal (Income)/loss per Book thru June 2019		1,039,453,535	(123,413,257)	(53,489,218)
10						
11	4	Remove Non Utility Expenses net of revenues (charitable, civic, legislative, merchandising, etc.)		(47,774,712)	(824,488)	(4,038,293)
12	5	Remove 50% of Meals Expense		(2,205,188)	(290,847)	(439,190)
13	6	Remove Non-deductible Parking (Including Allocated portion of Shared Costs)			(21,816)	(21,816)
14	7	Reverse Pension/OPEB Expense Regulatory Deferrals			88,263	88,263
15	8	Reflect Addition Pension Deductions per Tax based on Funding level			3,377,129	3,377,129
16	9	Reverse Section 8.209 Deferral			60,592	60,592
17	10	Subtotal Adjusted (Income)/loss per Book thru June 2019		989,473,636	(121,024,426)	(54,462,534)
18						
19	11	Reverse Book Depreciation	2	(150,377,220)	(25,614,798)	(35,730,674)
20	12	Deduct Allocated OneGas Tax Depreciation	4	66,446,575		4,469,861
21	13	Deduct TGS Division Tax Depreciation	4	8,253,107	91,197,194	91,752,380
22	14	Total Depreciation Related Adjustments Impacting Jurisdiction		(75,677,537)	65,582,396	60,491,568
23						
24	15	Subtotal - Pre Tax Net (Income)/loss after adjustments		913,796,098	(55,442,030)	6,029,033
25	16	Allocate to Central Gulf Service Area		6.7270%	100.0000%	
26	17	Subtotal - Jurisdictional Pre Tax Net (Income)/loss before Tax Adj	3	61,471,064	(55,442,030)	6,029,033
27						
28	18	Tax Rate		21%	21%	21%
29						
30	19	NOL ADIT Adjustment	5 and 6	12,908,923	(11,642,826)	1,266,097
31						0

Notes:

1. Reclassification of cost to align jurisdiction gas cost revenue with gas cost expense

2. Prior to 2009 Depreciation for all TGS jurisdictions was recorded to division office rather than local jurisdiction cost centers. Since book depreciation is entirely reversed and replaced with tax depreciation, no reclassification of book depreciation was made above. Instead, book depreciation is reversed from the cost center group to which it was actually recorded

3. Allocation of Shared Costs to Service Area

	Alloc to Gulf	Total Alloc to Central Gulf
Allocable Shared Service Costs	913,755,832	
Gulf Customers as of 6/30/2019	44,622	
Total TGS Customers as of 6/30/2019	663,330	
Allocation Factor	6.7270%	6.7270%
	61,468,355	61,468,355

4 - "Tax Depreciation" represents all book vs. tax plant-related timing differences including the excess of tax depreciation (including tax bonus depreciation) over book depreciation; amounts expensed per tax as repairs expense but but capitalized as additions per book; cost of removal deducted as expense per tax but taken to accumulated depreciation per book; the impact of any write off to expense of the net book value for tax purposes at the time of retirement, and CIAC credits taxed as income when received for tax purposes but deducted from plant basis per book.

5. If the NOL ADIT adjustment is a credit amount (negative amount), the carryforward to the summary ADFIT page will be zero since that means that there is net taxable income rather than a tax NOL (net operating loss).

6. If adding the NOL to the jurisdiction's other ADFIT components results in a net ADFIT debit, only add in only enough of the NOL above to bring the total net ADFIT for the jurisdiction to $0.

TGS Division Assets
Estimated Accumulated Deferred Income Tax Analysis
As of September 30, 2019

Row	A	B	C	D	E	G	H	I	K	L
7–11			(1010 & 1060) **Book Basis**	(1080100 & 1110) **Book Reserve**	**Net Book Basis**	(1010 & 1060) **Tax Basis**	(1080100 & 1110) **Tax Reserve**	**Net Tax Basis**	**Timing Difference**	**TOTAL ADIT Asset/(Liability) (incl. Excess ADIT) 09/30/2019** 21% tax rate
12	TGS Division unadjusted		4,884,925	(342,878)	4,542,047	5,403,028	(4,162,266)	1,240,762	3,301,286	(693,270)
14	**Adjustments**									
15	301	Organization Costs	(127,437)	127,437	-	(104,835)		(104,835)	104,835	(22,015)
16	303	Intangible Property	(278,560)	278,560	-	(229,154)		(229,154)	229,154	(48,122)
17	376	Mains	-		-			-	-	-
18	389	Land & Land Rights	527,777		527,777	527,777		527,777	-	-
19	390.1	Structures & Improvements	2,907,882	(5,304)	2,902,578	2,907,882		2,907,882	(5,304)	1,114
20	390.2	Leasehold Equipment	(43,351)	43,745	394	(43,351)		(43,351)	43,745	(9,186)
21	390.21	Leasehold Equipment EOL			-			-	-	-
22	391.1	Office Furniture & Fixtures	-	(48,803)	(48,803)	-	-	-	(48,803)	10,249
23	391.2	Data Processing Equipment			-			-	-	-
24	391.2	Radio Towers			-			-	-	-
25	391.3	Office Machines			-			-	-	-
26	391.4	Audio Visual Equipment			-			-	-	-
27	391.5	Artwork			-			-	-	-
28	391.6	Purchased Software			-	-		-	-	-
29	391.9	Micro Computer Equipment	(11,143)	(2,992,047)	(3,003,190)	(6,475)	5,407	(1,068)	(3,002,122)	630,446
30	392.2	Pickup Trucks and Vans			-			-	-	-
31	392.3	Trucks 3/4 to 3 Ton			-			-	-	-
32	392.5	Trailers			-			-	-	-
33	392.6	Aircraft			-			-	-	-
34	394	Tools	(262)	(1,108)	(1,370)	(131)	91	(40)	(1,330)	279
35	394.2	Shop Equipment			-			-	-	-
36	397	Communication Equipment	-	(24,615)	(24,615)			-	(24,615)	5,169
37	398	Miscellaneous Equipment		-	-			-	-	-
38	Total Adjustments		2,974,907	(2,622,136)	352,771	3,051,713	5,498	3,057,211	(2,704,441)	567,934
40	TGS Division Adjusted		7,859,832	(2,965,014)	4,894,818	8,454,741	(4,156,768)	4,297,973	596,845	(125,336)
41	CTGCSA Allocation Factor		6.7270%	6.7270%	6.7270%	6.7270%	6.7270%	6.7270%	6.7270%	6.7270%
42	Total Division Allocated to CTGCSA		528,731	(199,456)	329,274	568,750	(279,626)	289,125	40,150	(8,431)
44		Per WKP C.b.1 Post Test Year Div	4,423,681							
45		Per WKP C-1.b.1 Post Test Yr Div	3,436,151				Service Area's % of customers			6.7270%
46		Per WKP D.b.1 Post Test Yr Div		(2,965,014)			(Input jurisdiction's factor on version pasted to juridictional ADIT file)			
47			7,859,832	(2,965,014)						
48		Difference	(0)	-			Service Area's allocated piece of ADFIT			(8,431)

ONEGAS, Inc. (Corporate Assets)
Estimated Accumulated Deferred Income Tax Analysis
As of Sept 30, 2019

Plant Acct	Description	A (1010 & 1060) Book Basis	B (1080100 & 1110) Book Reserve	Net Book Basis	C (1010 & 1060) Gross Tax Basis	D (1080100 & 1110) Tax Reserve	Net Tax Basis	Total Timing Difference	Estimated ADIT Asset/(Liability) 9/30/2019	Allocation Factor to TGS	Timing Diff Allocated to TGS Divison	Deferred Tax Allocated to TGS Divison
									21% tax rate			
	Total ONEGAS unadjusted	241,036,494.14	(75,362,258.66)	165,674,235	162,825,248	(114,947,039)	47,878,208	117,796,027	(24,737,166)			
389	Land & Land Rights	-	-	-	-	-	-	-	-	25.01%	-	-
391.1	Office Furniture & Equipment	255,010.17	(1,415.66)	253,595	255,011	(4,336)	250,674	2,920	(613)	25.01%	730	(153)
390.2	Leasehold Improvements	5,382,079.48	(2,133,609.48)	3,248,470	4,085,993	(582,723)	3,503,270	(254,800)	53,508	25.01%	(63,725)	13,382
391.1	Office Furniture & Equipment	3,605,934.31	(858,752.83)	2,747,181	433,067	(15,930)	417,138	2,330,044	(489,309)	25.01%	582,744	(122,376)
390.19	Airplane Hanger Furniture	11,869.56	(3,388.12)	8,481	-	-	-	8,481	(1,781)	25.01%	2,121	(445)
391.3	Office Machines	36,236.76	(14,326.54)	21,910	15,646	(567,812)	(552,165)	574,075	(120,556)	25.01%	143,576	(30,151)
391.4	Audio Visual Equipment	1,402,299.01	(1,090,137.83)	312,161	755,768	(665,652)	90,115	222,046	(46,630)	25.01%	55,534	(11,662)
391.5	Artwork	49,413.97	(10,635.21)	38,779	-	-	-	38,779	(8,144)	25.01%	9,699	(2,037)
391.6	Purchased Software	117,635,422.55	(27,642,554.79)	89,992,868	58,416,474	(25,102,761)	33,313,713	56,679,154	(11,902,622)	25.01%	14,175,457	(2,976,846)
391.6	Banner Software	5,471,958.05	(1,292,481.60)	4,179,476	12,465,023	(13,493,271)	(1,028,248)	5,207,724	(1,093,622)	30.41%	1,583,673	(332,571)
391.6	PowerPlant	870,000.01	(361,608.25)	508,392	870,000	(356,874)	513,126	(4,734)	994	24.02%	(1,137)	239
391.6	Maximo	3,117,560.99	(2,253,129.05)	864,432	3,117,561	(3,357,301)	(239,740)	1,104,172	(231,876)	24.71%	272,826	(57,293)
391.6	Concur Project	47,647.71	(47,647.71)	-	47,648	(47,648)	-	-	-	27.95%	-	-
391.6	Journey- Employee - ODC Distrigas	69,580,939.55	(26,272,810.56)	43,308,129	38,295,750	(33,222,433)	5,073,317	38,234,812	(8,029,311)	25.01%	9,562,527	(2,008,131)
391.6	Journey - Employee Count	1,848,836.03	(833,622.36)	1,015,214	-	-	-	1,015,214	(213,195)	27.95%	283,752	(59,588)
391.6	Ariba Software	-	-	-	-	-	-	-	-	30.96%	-	-
391.6	Ariba Software	903,328.29	(141,533.60)	761,795			-	761,795	(159,977)	30.96%	235,852	(49,529)
391.8	Micro Computer Equipment	16,975,889.07	(4,466,695.70)	12,509,193	10,434,136	(3,949,873)	6,484,263	6,024,930	(1,265,235)	25.01%	1,506,835	(316,435)
391.81	Aircraft Computer Equipment	130,857.17	(82,058.30)	48,799			-	48,799	(10,248)	25.01%	12,205	(2,563)
392.6	Aircraft	13,608,722.55	(7,845,188.51)	5,763,534	13,541,078	(13,515,102)	25,976	5,737,558	(1,204,887)	25.01%	1,434,963	(301,342)
397	Communicaton Equipment	102,488.60	(10,662.56)	91,826	20,092,094	(20,065,323)	26,771	65,055	(13,662)	25.01%	16,270	(3,417)
	Total ONEGAS unadjusted	241,036,493.83	(75,362,258.66)	165,674,235.17	162,825,248.21	(114,947,039.00)	47,878,209.21	117,796,025.96	(24,737,166.00)		29,813,901	(6,260,919)
		(0)	-	0	(0)	0	(1)	1	-			
Adjustments												
389	Land & Land Rights	-	-	-	-	-	-	-	-	25.01%	-	-
390.2	Leasehold Improvements	(52.09)		(52)	(52)	3	(49)	(3)	1	25.01%	(1)	0
390.19	Airplane Hanger Furniture	(11,869.56)	3,388.12	(8,481)	-	-	-	(8,481)	1,781	25.01%	(2,121)	445
391.5	Artwork	(49,413.97)	10,635.21	(38,779)	-	-	-	(38,779)	8,144	25.01%	(9,699)	2,037
391.6	Banner Software	(355.00)		(355)	(178)	-	(178)	(178)	37	30.41%	(54)	11
391.6	Purchased Software	(157,783.28)	56,619.44	(101,164)	(78,892)	65,743	(13,149)	(88,015)	18,483	25.01%	(22,013)	4,623
391.6	Journey- Employee - ODC Distrigas	(12,655.29)		(12,655)	(6,328)	-	(6,328)	(6,328)	1,329	25.01%	(1,583)	332
391.8	Micro Computer Equipment	(280.25)	-	(280)	(140)	-	(140)	(140)	29	25.01%	(35)	7
391.81	Aircraft Computer Equipment	(130,857.17)	82,058.30	(48,799)	(65,429)	65,426	(3)	(48,796)	10,247	25.01%	(12,204)	2,563
392.6	Aircraft	(13,608,722.55)	7,845,188.51	(5,763,534)	(13,541,078)	13,515,102	(25,976)	(5,737,558)	1,204,887	25.01%	(1,434,963)	301,342
397.2	Communicaton Equipment		-	-	-	-	-	-	-	25.01%	-	-
	Subtotal Adjustments	(13,971,989.16)	7,997,889.58	(5,974,099.58)	(13,692,095.36)	13,646,273.80	(45,821.55)	(5,928,278.03)	1,244,938.00		(1,482,672)	311,361
	Total Adjusted	227,064,504.67	(67,364,369.08)	159,700,135.59	149,133,152.86	(101,300,765.20)	47,832,387.66	111,867,747.93	(23,492,228.00)		28,331,229	(5,949,558)
				-					1			

Plant Acct	Description	(1010 & 1060) Book Basis Allocated to TGS	(1080100 & 1110) Book Reserve Allocated to TGS	Net Book Basis Allocated to TGS		(1010 & 1060) Gross Tax Basis Allocated to TGS	(1080100 & 1110) Tax Reserve Allocated to TGS	Net Tax Basis Allocated to TGS	Total Allocated Timing Difference	Allocated TOTAL ADIT Asset/(Liability) (incl. Excess ADIT) 9/30/2019
										21% tax rate
	Total ONEGAS unadjusted	60,670,169	(18,941,838)	41,728,332		41,379,064	(29,464,633)	11,914,431	29,813,901	(6,260,919)
389	Land & Land Rights	-	-	-		-	-	-	-	-
391.1	Office Furniture & Equipment	63,778	(354)	63,424		63,778	(1,085)	62,694	730	(153)
390.2	Leasehold Improvements	1,346,058	(533,616)	812,442		1,021,907	(145,739)	876,168	(63,725)	13,382
391.1	Office Furniture & Equipment	901,844	(214,774)	687,070		108,310	(3,984)	104,326	582,744	(122,376)
390.19	Airplane Hanger Furniture	2,969	(847)	2,121		-	-	-	2,121	(445)
391.3	Office Machines	9,063	(3,583)	5,480		3,913	(142,010)	(138,096)	143,576	(30,151)
391.4	Audio Visual Equipment	350,715	(272,643)	78,072		189,017	(166,480)	22,538	55,534	(11,662)
391.5	Artwork	12,358	(2,660)	9,699		-	-	-	9,699	(2,037)
391.6	Purchased Software	29,420,619	(6,913,403)	22,507,216		14,609,960	(6,278,200)	8,331,760	14,175,457	(2,976,846)
391.6	Banner Software	1,664,027	(393,045)	1,270,982		3,790,623	(4,103,314)	(312,691)	1,583,673	(332,571)
391.6	PowerPlant	208,931	(86,840)	122,090		208,931	(85,703)	123,227	(1,137)	239
391.6	Maximo	770,306	(556,717)	213,589		770,306	(829,543)	(59,237)	272,826	(57,293)
391.6	Concur Project	13,317	(13,317)	-		13,317	(13,317)	-	-	-
391.6	Journey- Employee - ODC Distrigas	17,402,193	(6,570,830)	10,831,363		9,577,767	(8,308,931)	1,268,837	9,562,527	(2,008,131)
391.6	Journey - Employee Count	516,750	(232,997)	283,752		-	-	-	283,752	(59,588)
391.6	Ariba Software	-	-	-		-	-	-	-	-
391.6	Ariba Software	279,670	(43,819)	235,852		-	-	-	235,852	(49,529)
391.8	Micro Computer Equipment	4,245,670	(1,117,121)	3,128,549		2,609,577	(987,863)	1,621,714	1,506,835	(316,435)
391.81	Aircraft Computer Equipment	32,727	(20,523)	12,205		-	-	-	12,205	(2,563)
392.6	Aircraft	3,403,542	(1,962,082)	1,441,460		3,386,624	(3,380,127)	6,496	1,434,963	(301,342)
397	Communicaton Equipment	25,632	(2,667)	22,966		5,025,033	(5,018,337)	6,695	16,270	(3,417)
	Total ONEGAS unadjusted	60,670,169	(18,941,838)	41,728,332		41,379,064	(29,464,633)	11,914,431	29,813,901	(6,260,919)
Adjustments										
389	Land & Land Rights	-	-	-		-	-	-	-	-
390.2	Leasehold Improvements	(13)	-	(13)		(13)	1	(12)	(1)	0
390.19	Airplane Hanger Furniture	(2,969)	847	(2,121)		-	-	-	(2,121)	445
391.5	Artwork	(12,358)	2,660	(9,699)		-	-	-	(9,699)	2,037
391.6	Banner Software	(108)	-	(108)		(54)	-	(54)	(54)	11
391.6	Purchased Software	(39,462)	14,161	(25,301)		(19,731)	16,442	(3,288)	(22,013)	4,623
391.6	Journey- Employee - ODC Distrigas	(3,165)	-	(3,165)		(1,583)	-	(1,583)	(1,583)	332
391.8	Micro Computer Equipment	(70)	-	(70)		(35)	-	(35)	(35)	7
391.81	Aircraft Computer Equipment	(32,727)	20,523	(12,205)		(16,364)	16,363	(1)	(12,204)	2,563
392.6	Aircraft	(3,403,542)	1,962,082	(1,441,460)		(3,386,624)	3,380,127	(6,496)	(1,434,963)	301,342
397.2	Communicaton Equipment	-	-	-		-	-	-	-	-
	Subtotal Adjustments	(3,494,414)	2,000,272	(1,494,141)		(3,424,403)	3,412,933	(11,470)	(1,482,672)	311,361
	Total Adjusted	57,175,756	(16,941,566)	40,234,190	(A)	37,954,661	(26,051,700)	11,902,961	28,331,229	(5,949,558)
		6.7270%	6.7270%	6.7270%		6.7270%	6.7270%	6.7270%	6.7270%	6.7270%
		3,846,213	(1,139,659)	2,706,554		2,553,210	(1,752,498)	800,712	1,905,842	(400,227)

Service Area's % of customers: 6.7270%
(Input jurisdiction's factor on version pasted to juridictional ADIT file)

Service Area's allocated piece of ADFIT on plant: (400,227)

	Book Basis Allocated to TGS	Book Reserve Allocated to TGS
Per WKP C.c Corp Plant	48,700,525	
Per WKP C-1.c Corp CCNC	8,475,214	
Per WKP D.c Corp Reserves		(16,941,570)
	57,175,739	(16,941,570)
Difference (immaterial/rounding)	16.62	4.01

	A	B	C	D	E	F	G	H	I	J	K	L
1												
2	**Calculation of ADIT re GCSA Repair Adjustment**											
3												
4												
5		**Per Tax Report 30:**										
6		2008 Tax Repair Blankets	2008 Tax Repair Bonus	2008 Tax Repair Bonus Depr Adju	2008 Tax Repair Expense	2009 Tax Repair Blankets	2009 Tax Repair Bonus	2009 Tax Repair Bonus Depr Adju	2009 Tax Repair Expense	Tax Expensing (2010-2018 Tax Repair)	Total Tax Repairs Adjustment	ADIT Asset/(Liability) at 21%
7	Galveston	(2,562)	72,631	219,887	(346,709)	(162,975)	102,808	385,874	(1,004,946)	(3,190,231)	(3,926,223)	(824,507)
8	South Jefferson County	(1,778,131)	1,004,601	998,600	(3,070,267)	(196,135)	165,813	1,164,659	(3,202,371)	(8,295,186)	(13,208,417)	(2,773,768)
9	Total Gulf Coast Area	(1,780,693)	1,077,232	1,218,487	(3,416,976)	(359,111)	268,621	1,550,533	(4,207,316)	(11,485,417)	(17,134,641)	(3,598,275)
10												
11												
12												

	A	B	C	D	E	F	G	H	I	J
1	**ARAM Estimate for amounts attributed TO the Gulf Coast SERVICE ARE/**									
2	**9.30.2019**									
3										
4										
5										
6	**Estimated Accumulated Deferred Income Taxes for:**		**Excess ADIT**		**Protected**	**Unprotected**		**TGS Amortization Amount**	**ONE Gas Amortization Amount**	**2018 Amortization**
7	**Gulf Coast Service Area Plant Assets Depreciatior**		(5,269,984)		(5,269,984)			(5,269,984)		26,992
8	**Gulf Coast Service Area Repairs**		(2,302,998)			(2,302,998)		(2,302,998)		247,559
9	**Gulf Coast Service Area Other Rate Base Items**		(459,628)			(459,628)		(459,628)		45,963
10	**TGS Division Plant Assets Depreciation**		(39,261)		(39,261)			(39,261)		9,715
11	**ONEGAS Plant Assets Depreciation**		(233,209)		(233,209)				(233,209)	26,146
12	**Gulf Coast Service Area NOL**		1,772,469		1,772,469			1,772,469		(66,836)
13										
14	**ADFIT - Accumulated Deferred Federal Income Taxes**		(6,532,611)		(3,769,985)	(2,762,626)		(6,299,402)	(233,209)	289,538
15										
16	Percent Protected				58%					
17	**GCSA**									
18			TGS Amortization	ONE Gas Amortization	TGS NOL	OGS NOL		Total Amortization		
19	Year 1 - 2018 Actuals		$ 330,229	$ 26,146	$ (66,836)	$ 66,836		$ 289,538		
20										
21										

GCSA (Gulf Coast) - Galveston, South Jefferson

Rate Filing	Sum of Beg APB11 DIT	Sum of End APB11 DIT	Sum of Beg Timing Diff	Sum of End Timing Diff	Sum of APB11 DIT Provision	Sum of APB11 DIT Reversal	Sum of Beg FAS109 DIT	Sum of Beg Reg Liab Pre Grossup	Sum of Reg Liability Reversal	
2017	**17,550,044**	**18,202,394**	**50,142,982**	**52,006,839**			**18,202,394**	**(7,280,957)**		
2018	18,202,394	18,059,403	52,006,839	52,633,319	352,915	(495,905)	18,059,403	**(7,006,406)**	274,551	3.771%

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PowerTax Deferred Tax Summary Report

2018 AS FILED Tax Return FINAL
091 Texas Gas Service

Grouped By: Total Tax Classes

Jurisdiction: Federal Rate Cas Tax Year: 2018	Beginning Difference	Current Difference	Ending Difference	Beginning APB11 DFIT Balance	Current DFIT	Ending APB11 DFIT Balance	End FAS109 Liability @ Stat Rate	Regulatory Asset Before Gross-Up	Regulatory Liab Before Gross-Up	Regulatory Asset After Gross-Up	Regulatory Liab After Gross-Up
TGS Fed RC M/L	$34,324,047.07	$951,039.04	$35,275,086.11	$12,013,416.47	$172,726.43	$12,186,142.90	$7,407,768.08	($0.01)	($4,778,374.81)	($0.01)	($6,048,575.71)
Depreciation Difference	**$34,324,047.07**	**$951,039.04**	**$35,275,086.11**	**$12,013,416.47**	**$172,726.43**	**$12,186,142.90**	**$7,407,768.08**	**($0.01)**	**($4,778,374.81)**	**($0.01)**	**($6,048,575.71)**
Federal Rate Case Amortization	$0.00	$0.00	$0.00	$2,475,590.73	($247,559.10)	$2,228,031.63	$0.00	$0.00	($2,228,031.63)	$0.00	($2,228,031.63)
Depreciation Difference	**$0.00**	**$0.00**	**$0.00**	**$2,475,590.73**	**($247,559.10)**	**$2,228,031.63**	**$0.00**	**$0.00**	**($2,228,031.63)**	**$0.00**	**($2,228,031.63)**
TGS Fed RC 2008 Tax Rep Blank 4	$1,326,067.60	($49,145.34)	$1,276,922.26	$278,474.19	($10,320.52)	$268,153.67	$268,153.67	$0.00	$0.00	$0.00	$0.00
TGS Fed RC 2008 Tax Rep Exp 48	$2,566,454.77	($93,649.08)	$2,472,805.69	$538,955.52	($19,666.30)	$519,289.22	$519,289.19	($0.00)	($0.02)	($0.00)	($0.03)
TGS Fed RC 2009 Tax Rep Blank 4	$306,112.82	($9,611.55)	$296,501.27	$64,283.69	($2,018.43)	$62,265.26	$62,265.27	$0.00	$0.00	$0.00	$0.00
TGS Fed RC 2009 Tax Rep Exp 48	$3,401,322.49	($114,249.32)	$3,287,073.17	$714,277.73	($23,992.36)	$690,285.37	$690,285.37	($0.00)	($0.00)	($0.00)	($0.01)
TGS Fed RC Tax Expensing	$9,604,611.56	$542,510.91	$10,147,122.47	$2,016,968.42	$113,927.30	$2,130,895.72	$2,130,895.72	$0.13	($0.13)	$0.16	($0.17)
Book Overhead	**$17,204,569.24**	**$275,855.62**	**$17,480,424.86**	**$3,612,959.55**	**$57,929.69**	**$3,670,889.24**	**$3,670,889.22**	**$0.13**	**($0.15)**	**$0.17**	**($0.19)**
TGS Fed RC 2008 Tax Rep Bonus	($831,259.00)	$55,568.80	($775,690.20)	($174,564.39)	$11,669.46	($162,894.93)	($162,894.94)	($0.02)	$0.01	($0.02)	$0.01
TGS Fed RC 2008 Tax Rep Bonus-	($380,277.27)	$48,066.07	($332,211.20)	($79,858.23)	$10,093.87	($69,764.36)	($69,764.35)	$0.00	$0.00	$0.00	$0.01
TGS Fed RC 2009 Tax Rep Bonus	($227,125.13)	$24,198.09	($202,927.04)	($47,696.27)	$5,081.60	($42,614.67)	($42,614.68)	($0.01)	$0.00	($0.01)	$0.00
TGS Fed RC 2009 Tax Rep Bonus-	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TGS Fed RC 8.209 ROE	($597,044.55)	($70,841.36)	($667,885.91)	($125,379.37)	($14,876.71)	($140,256.08)	($140,256.04)	($0.00)	$0.04	($0.00)	$0.05
TGS Fed RC CIAC	($1,720,663.70)	$25,301.86	($1,695,361.84)	($361,339.35)	$5,313.37	($356,025.98)	($356,025.99)	($0.11)	$0.11	($0.14)	$0.13
TGS Fed RC Fed RC Only B/T Diff	($1,267,152.01)	$296,450.08	($970,701.93)	($266,101.93)	$62,254.53	($203,847.40)	($203,847.41)	$0.01	($0.01)	$0.01	($0.01)
TGS Fed RC Non-Fed/State B/T Di	$5,501,744.56	($979,158.67)	$4,522,585.89	$1,155,366.36	($205,623.33)	$949,743.03	$949,743.04	$0.04	($0.03)	$0.05	($0.04)
Tax Overhead	**$478,222.90**	**($600,415.13)**	**($122,192.23)**	**$100,426.82**	**($126,087.21)**	**($25,660.39)**	**($25,660.37)**	**($0.09)**	**$0.11**	**($0.11)**	**$0.14**
Total Tax Classes	**$52,006,839.21**	**$626,479.53**	**$52,633,318.74**	**$18,202,393.57**	**($142,990.19)**	**$18,059,403.38**	**$11,052,996.94**	**$0.03**	**($7,006,406.48)**	**$0.04**	**($8,276,607.39)**
Jurisdiction Totals:	**$52,006,839.21**	**$626,479.53**	**$52,633,318.74**	**$18,202,393.57**	**($142,990.19)**	**$18,059,403.38**	**$11,052,996.94**	**$0.03**	**($7,006,406.48)**	**$0.04**	**($8,276,607.39)**
Company Totals:	**$52,006,839.21**	**$626,479.53**	**$52,633,318.74**	**$18,202,393.57**	**($142,990.19)**	**$18,059,403.38**	**$11,052,996.94**	**$0.03**	**($7,006,406.48)**	**$0.04**	**($8,276,607.39)**

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091 Texas Gas Service
PowerTax Deferred Tax Summary Report
Grouped By: Total Tax Classes

Jurisdiction : Federal Rate Case Tax Year : 2018	Beginning Difference	Provision	Reversal	Ending Difference	Beginning DFIT Balance	Current DFIT Provision	Current DFIT Reversal	Deferred Trans/Adj	Ending DFIT Balance
TGS Fed RC 2008 Tax Rep Blank 481a	$1,326,067.60	$0.00	($49,145.34)	$1,276,922.26	$278,474.19	$0.00	($10,320.52)	$0.00	$268,153.67
TGS Fed RC 2008 Tax Rep Exp 481a	$2,566,454.77	$0.00	($93,649.08)	$2,472,805.69	$538,955.52	$0.00	($19,666.30)	$0.00	$519,289.22
TGS Fed RC 2009 Tax Rep Blank 481a	$306,112.82	$0.00	($9,611.55)	$296,501.27	$64,283.69	$0.00	($2,018.43)	$0.00	$62,265.26
TGS Fed RC 2009 Tax Rep Exp 481a	$3,401,322.49	$0.00	($114,249.32)	$3,287,073.17	$714,277.73	$0.00	($23,992.36)	$0.00	$690,285.37
TGS Fed RC Tax Expensing	$9,604,611.56	$867,476.30	($324,965.39)	$10,147,122.47	$2,016,968.42	$182,170.04	($68,242.72)	$0.00	$2,130,895.72
Total Tax Classes	**$17,204,569.24**	**$867,476.30**	**($591,620.68)**	**$17,480,424.86**	**$3,612,959.55**	**$182,170.04**	**($124,240.33)**	**$0.00**	**$3,670,889.24**
Amortization Type Book Overhead Totals:	**$17,204,569.24**	**$867,476.30**	**($591,620.68)**	**$17,480,424.86**	**$3,612,959.55**	**$182,170.04**	**($124,240.33)**	**$0.00**	**$3,670,889.24**
Federal Rate Case Amortization	$0.00	$0.00	$0.00	$0.00	$2,475,590.73	$0.00	($247,559.10)	$0.00	$2,228,031.63
TGS Fed RC M/L	$34,324,047.07	$1,143,838.38	($192,799.34)	$35,275,086.11	$12,013,416.47	$240,206.06	($67,479.62)	$0.00	$12,186,142.90
Total Tax Classes	**$34,324,047.07**	**$1,143,838.38**	**($192,799.34)**	**$35,275,086.11**	**$14,489,007.20**	**$240,206.06**	**($315,038.72)**	**$0.00**	**$14,414,174.53**
Amortization Type Depreciation Difference Totals:	**$34,324,047.07**	**$1,143,838.38**	**($192,799.34)**	**$35,275,086.11**	**$14,489,007.20**	**$240,206.06**	**($315,038.72)**	**$0.00**	**$14,414,174.53**
TGS Fed RC 2008 Tax Rep Bonus Depr	($831,259.00)	$0.00	$55,568.80	($775,690.20)	($174,564.39)	$0.00	$11,669.46	$0.00	($162,894.93)
TGS Fed RC 2008 Tax Rep Bonus-Blank	($380,277.27)	$0.00	$48,066.07	($332,211.20)	($79,858.23)	$0.00	$10,093.87	$0.00	($69,764.36)
TGS Fed RC 2009 Tax Rep Bonus Depr	($227,125.13)	$0.00	$24,198.09	($202,927.04)	($47,696.27)	$0.00	$5,081.60	$0.00	($42,614.67)
TGS Fed RC 2009 Tax Rep Bonus-Blank	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TGS Fed RC 8.209 ROE	($597,044.55)	($130,058.17)	$59,216.81	($667,885.91)	($125,379.37)	($27,312.22)	$12,435.50	$0.00	($140,256.08)
TGS Fed RC CIAC	($1,720,663.70)	($200,711.34)	$226,013.20	($1,695,361.84)	($361,339.35)	($42,149.38)	$47,462.75	$0.00	($356,025.98)
TGS Fed RC Fed RC Only B/T Diff	($1,267,152.01)	$0.00	$296,450.08	($970,701.93)	($266,101.93)	$0.00	$62,254.53	$0.00	($203,847.40)
TGS Fed RC Non-Fed/State B/T Diff	$5,501,744.56	$0.00	($979,158.67)	$4,522,585.89	$1,155,366.36	$0.00	($205,623.33)	$0.00	$949,743.03
Total Tax Classes	**$478,222.90**	**($330,769.51)**	**($269,645.62)**	**($122,192.23)**	**$100,426.82**	**($69,461.60)**	**($56,625.62)**	**$0.00**	**($25,660.39)**
Amortization Type Tax Overhead Totals:	**$478,222.90**	**($330,769.51)**	**($269,645.62)**	**($122,192.23)**	**$100,426.82**	**($69,461.60)**	**($56,625.62)**	**$0.00**	**($25,660.39)**
Jurisdiction Totals:	**$52,006,839.21**	**$1,680,545.17**	**($1,054,065.64)**	**$52,633,318.74**	**$18,202,393.57**	**$352,914.50**	**($495,904.67)**	**$0.00**	**$18,059,403.38**
Company Totals:	**$52,006,839.21**	**$1,680,545.17**	**($1,054,065.64)**	**$52,633,318.74**	**$18,202,393.57**	**$352,914.50**	**($495,904.67)**	**$0.00**	**$18,059,403.38**

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PowerTax Deferred Tax Summary Report

2017 AS FILED Year End Tax Return
091 Texas Gas Service

Grouped By: Total Tax Classes

Jurisdiction: Federal Rate Case Tax Year: 2017	Beginning Difference	Current Difference	Ending Difference	Beginning APB11 DFIT Balance	Current DFIT	Ending APB11 DFIT Balance	End FAS109 Liability @ Stat Rate	Regulatory Asset Before Gross-Up	Regulatory Liab Before Gross-Up	Regulatory Asset After Gross-Up	Regulatory Liab After Gross-Up
TGS Fed RC M/L	$32,774,510.30	$1,549,536.77	$34,324,047.07	$11,471,078.64	$542,337.83	$12,013,416.47	$12,013,416.47	$0.37	($0.37)	$0.57	($0.57)
Depreciation Difference	**$32,774,510.30**	**$1,549,536.77**	**$34,324,047.07**	**$11,471,078.64**	**$542,337.83**	**$12,013,416.47**	**$12,013,416.47**	**$0.37**	**($0.37)**	**$0.57**	**($0.57)**
TGS Fed RC 2008 Tax Rep Blank -	$1,375,476.05	($49,408.45)	$1,326,067.60	$481,416.61	($17,292.95)	$464,123.66	$464,123.66	($0.00)	$0.00	($0.00)	$0.00
TGS Fed RC 2008 Tax Rep Exp 48	$2,662,219.12	($95,764.35)	$2,566,454.77	$931,776.68	($33,517.52)	$898,259.16	$898,259.17	$0.01	($0.00)	$0.02	($0.01)
TGS Fed RC 2009 Tax Rep Blank -	$316,483.28	($10,370.46)	$306,112.82	$110,769.14	($3,629.66)	$107,139.48	$107,139.49	($0.00)	$0.01	($0.00)	$0.01
TGS Fed RC 2009 Tax Rep Exp 48	$3,520,693.35	($119,370.86)	$3,401,322.49	$1,232,242.67	($41,779.81)	$1,190,462.86	$1,190,462.87	$0.01	$0.00	$0.02	$0.00
TGS Fed RC Tax Expensing	$8,402,027.23	$1,202,584.33	$9,604,611.56	$2,940,709.51	$420,904.46	$3,361,613.97	$3,361,614.05	$0.09	($0.02)	$0.14	($0.03)
Book Overhead	**$16,276,899.03**	**$927,670.21**	**$17,204,569.24**	**$5,696,914.61**	**$324,684.52**	**$6,021,599.13**	**$6,021,599.23**	**$0.12**	**($0.01)**	**$0.18**	**($0.02)**
TGS Fed RC 2008 Tax Rep Bonus	($887,264.25)	$56,005.25	($831,259.00)	($310,542.49)	$19,601.83	($290,940.66)	($290,940.65)	($0.01)	$0.02	($0.01)	$0.03
TGS Fed RC 2008 Tax Rep Bonus	($428,332.59)	$48,055.32	($380,277.27)	($149,916.41)	$16,819.36	($133,097.05)	($133,097.04)	$0.00	$0.01	$0.00	$0.01
TGS Fed RC 2009 Tax Rep Bonus	($257,055.31)	$29,930.18	($227,125.13)	($89,969.36)	$10,475.56	($79,493.80)	($79,493.80)	$0.00	$0.00	$0.01	$0.00
TGS Fed RC 2009 Tax Rep Bonus	($3,502.36)	$3,502.36	$0.00	($1,225.83)	$1,225.83	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TGS Fed RC 8.209 ROE	($488,584.02)	($108,460.53)	($597,044.55)	($171,004.41)	($37,961.19)	($208,965.60)	($208,965.59)	($0.01)	$0.01	($0.01)	$0.02
TGS Fed RC CIAC	($1,768,192.56)	$47,528.86	($1,720,663.70)	($618,867.41)	$16,635.07	($602,232.34)	($602,232.30)	($0.01)	$0.06	($0.02)	$0.09
TGS Fed RC Fed RC Only B/T Diff	($1,557,499.88)	$290,347.87	($1,267,152.01)	($545,124.96)	$101,621.76	($443,503.20)	($443,503.20)	$0.00	($0.01)	$0.01	($0.01)
TGS Fed RC Non-Fed/State B/T D	$6,482,003.88	($980,259.32)	$5,501,744.56	$2,268,701.38	($343,090.76)	$1,925,610.62	$1,925,610.60	$0.02	($0.04)	$0.03	($0.06)
Tax Overhead	**$1,091,572.91**	**($613,350.01)**	**$478,222.90**	**$382,050.51**	**($214,672.54)**	**$167,377.97**	**$167,378.01**	**$0.00**	**$0.04**	**$0.00**	**$0.07**
Total Tax Classes	**$50,142,982.24**	**$1,863,856.97**	**$52,006,839.21**	**$17,550,043.76**	**$652,349.81**	**$18,202,393.57**	**$18,202,393.72**	**$0.49**	**($0.34)**	**$0.75**	**($0.52)**
Jurisdiction Totals:	**$50,142,982.24**	**$1,863,856.97**	**$52,006,839.21**	**$17,550,043.76**	**$652,349.81**	**$18,202,393.57**	**$18,202,393.72**	**$0.49**	**($0.34)**	**$0.75**	**($0.52)**
Company Totals:	**$50,142,982.24**	**$1,863,856.97**	**$52,006,839.21**	**$17,550,043.76**	**$652,349.81**	**$18,202,393.57**	**$18,202,393.72**	**$0.49**	**($0.34)**	**$0.75**	**($0.52)**

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2017 AS FILED Year End Tax Return
091 Texas Gas Service
PowerTax Deferred Tax Summary Report
Grouped By: Total Tax Classes

Jurisdiction : Federal Rate Case Tax Year : 2017	Beginning Difference	Provision	Reversal	Ending Difference	Beginning DFIT Balance	Current DFIT Provision	Current DFIT Reversal	Deferred Trans/Adj	Ending DFIT Balance
TGS Fed RC 2008 Tax Rep Blank 481a	$6,146.47	$0.00	($89.94)	$6,056.53	$2,151.26	$0.00	($31.48)	$0.00	$2,119.78
TGS Fed RC 2008 Tax Rep Exp 481a	$218,793.82	$0.00	($10,515.19)	$208,278.63	$76,577.83	$0.00	($3,680.32)	$0.00	$72,897.51
TGS Fed RC 2009 Tax Rep Blank 481a	$133,657.64	$0.00	($4,947.54)	$128,710.10	$46,780.17	$0.00	($1,731.64)	$0.00	$45,048.53
TGS Fed RC 2009 Tax Rep Exp 481a	$768,896.54	$0.00	($30,490.56)	$738,405.98	$269,113.79	$0.00	($10,671.70)	$0.00	$258,442.09
TGS Fed RC Tax Expensing	$2,002,957.19	$751,991.47	($96,785.92)	$2,658,162.74	$701,035.04	$263,197.03	($33,875.11)	$0.00	$930,356.96
Total Tax Classes	**$3,130,451.66**	**$751,991.47**	**($142,829.15)**	**$3,739,613.98**	**$1,095,658.09**	**$263,197.03**	**($49,990.25)**	**$0.00**	**$1,308,864.87**
Amortization Type Book Overhead Totals:	**$3,130,451.66**	**$751,991.47**	**($142,829.15)**	**$3,739,613.98**	**$1,095,658.09**	**$263,197.03**	**($49,990.25)**	**$0.00**	**$1,308,864.87**
TGS Fed RC M/L	$10,477,538.52	$1,145,289.66	($289,349.30)	$11,333,478.88	$3,667,138.57	$400,851.38	($101,272.19)	$0.00	$3,966,717.77
Total Tax Classes	**$10,477,538.52**	**$1,145,289.66**	**($289,349.30)**	**$11,333,478.88**	**$3,667,138.57**	**$400,851.38**	**($101,272.19)**	**$0.00**	**$3,966,717.77**
Amortization Type Depreciation Difference Totals:	**$10,477,538.52**	**$1,145,289.66**	**($289,349.30)**	**$11,333,478.88**	**$3,667,138.57**	**$400,851.38**	**($101,272.19)**	**$0.00**	**$3,966,717.77**
TGS Fed RC 2008 Tax Rep Bonus Depr	($65,037.62)	$0.00	$9,811.24	($55,226.38)	($22,763.16)	$0.00	$3,433.93	$0.00	($19,329.23)
TGS Fed RC 2008 Tax Rep Bonus-Blank	($19,993.06)	$0.00	$3,240.06	($16,753.00)	($6,997.57)	$0.00	$1,134.02	$0.00	($5,863.55)
TGS Fed RC 2009 Tax Rep Bonus Depr	($155,166.08)	$0.00	$18,567.11	($136,598.97)	($54,308.13)	$0.00	$6,498.49	$0.00	($47,809.64)
TGS Fed RC 2009 Tax Rep Bonus-Blank	($3,502.36)	$0.00	$3,502.36	$0.00	($1,225.83)	$0.00	$1,225.83	$0.00	$0.00
TGS Fed RC 8.209 ROE	($48,116.91)	($55,142.03)	$19,799.40	($83,459.54)	($16,840.92)	($19,299.71)	$6,929.79	$0.00	($29,210.84)
TGS Fed RC CIAC	($926,385.08)	($77,973.03)	$109,487.52	($894,870.59)	($324,234.79)	($27,290.58)	$38,320.67	$0.00	($313,204.72)
TGS Fed RC Fed RC Only B/T Diff	($785,156.22)	$0.00	$128,609.49	($656,546.73)	($274,804.68)	$0.00	$45,013.32	$0.00	($229,791.36)
TGS Fed RC Non-Fed/State B/T Diff	$2,438,977.74	$0.00	($390,648.77)	$2,048,328.97	$853,642.21	$0.00	($136,727.07)	$0.00	$716,915.14
Total Tax Classes	**$435,620.41**	**($133,115.06)**	**($97,631.59)**	**$204,873.76**	**$152,467.13**	**($46,590.29)**	**($34,171.02)**	**$0.00**	**$71,705.80**
Amortization Type Tax Overhead Totals:	**$435,620.41**	**($133,115.06)**	**($97,631.59)**	**$204,873.76**	**$152,467.13**	**($46,590.29)**	**($34,171.02)**	**$0.00**	**$71,705.80**
Jurisdiction Totals:	**$14,043,610.59**	**$1,764,166.07**	**($529,810.04)**	**$15,277,966.62**	**$4,915,263.79**	**$617,458.12**	**($185,433.46)**	**$0.00**	**$5,347,288.44**
Company Totals:	**$14,043,610.59**	**$1,764,166.07**	**($529,810.04)**	**$15,277,966.62**	**$4,915,263.79**	**$617,458.12**	**($185,433.46)**	**$0.00**	**$5,347,288.44**

WORKPAPERS

TO

DIRECT TESTIMONY

OF

RONALD E. WHITE

Workpapers to the Direct Testimony of Ronald E. White are voluminous and are being provided in electronic format.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

☒ Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended June 30, 2019 .
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

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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

On July 22, 2019 , the Company had 52,734,526 shares of common stock outstanding.

PART I - FINANCIAL INFORMATION
ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

ONE Gas, Inc.
CONSOLIDATED STATEMENTS OF INCOME

	Three Months Ended June 30,		Six Months Ended June 30,	
(Unaudited)	2019	2018	2019	2018
	(Thousands of dollars, except per share amounts)			
Total revenues	$ **290,560**	$ 292,521	$ **951,560**	$ 930,985
Cost of natural gas	**82,588**	94,159	**447,664**	444,578
Operating expenses				
Operations and maintenance	**101,482**	102,995	**209,757**	205,660
Depreciation and amortization	**44,943**	39,757	**88,789**	78,647
General taxes	**14,656**	14,567	**30,840**	30,767
Total operating expenses	**161,081**	157,319	**329,386**	315,074
Operating income	**46,891**	41,043	**174,510**	171,333
Other expense, net	**(865)**	(2,194)	**(436)**	(4,358)
Interest expense, net	**(15,399)**	(12,003)	**(31,185)**	(24,355)
Income before income taxes	**30,627**	26,846	**142,889**	142,620
Income taxes	**(6,157)**	(6,427)	**(24,759)**	(31,366)
Net income	$ **24,470**	$ 20,419	$ **118,130**	$ 111,254
Earnings per share				
Basic	$ **0.46**	$ 0.39	$ **2.23**	$ 2.11
Diluted	$ **0.46**	$ 0.39	$ **2.22**	$ 2.10
Average shares (*thousands*)				
Basic	**52,890**	52,692	**52,858**	52,648
Diluted	**53,215**	52,899	**53,210**	52,898
Dividends declared per share of stock	$ **0.50**	$ 0.46	$ **1.00**	$ 0.92

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.

CONSOLIDATED BALANCE SHEETS

(Unaudited)		June 30, 2019		December 31, 2018
		(Thousands of dollars)		
Assets				
Property, plant and equipment				
Property, plant and equipment	$	**6,241,105**	$	6,073,143
Accumulated depreciation and amortization		**1,840,457**		1,789,431
Net property, plant and equipment		**4,400,648**		4,283,712
Current assets				
Cash and cash equivalents		**11,114**		21,323
Accounts receivable, net		**169,801**		295,421
Materials and supplies		**50,344**		44,333
Natural gas in storage		**88,235**		107,295
Regulatory assets		**38,372**		54,420
Other current assets		**18,946**		20,495
Total current assets		**376,812**		543,287
Goodwill and other assets				
Regulatory assets		**424,304**		437,479
Goodwill		**157,953**		157,953
Other assets		**86,889**		46,211
Total goodwill and other assets		**669,146**		641,643
Total assets	$	**5,446,606**	$	5,468,642

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.

CONSOLIDATED BALANCE SHEETS

(Continued)

(Unaudited)		**June 30, 2019**		**December 31, 2018**
Equity and Liabilities		*(Thousands of dollars)*		
Equity and long-term debt				
Common stock, $0.01 par value: authorized 250,000,000 shares; issued and outstanding 52,734,222 shares at June 30, 2019; issued 52,598,005 and outstanding 52,564,902 shares at December 31, 2018	$	**527**	$	526
Paid-in capital		**1,725,843**		1,727,492
Retained earnings		**387,077**		320,869
Accumulated other comprehensive loss		**(4,984)**		(4,086)
Treasury stock, at cost: 33,103 shares at December 31, 2018		**—**		(2,145)
Total equity		**2,108,463**		2,042,656
Long-term debt, excluding current maturities, and net of issuance costs of $11,159 and $11,457, respectively		**1,285,811**		1,285,483
Total equity and long-term debt		**3,394,274**		3,328,139
Current liabilities				
Notes payable		**293,000**		299,500
Accounts payable		**67,578**		174,510
Accrued taxes other than income		**37,312**		47,640
Regulatory liabilities		**46,534**		48,394
Customer deposits		**58,831**		61,183
Other current liabilities		**75,098**		67,664
Total current liabilities		**578,353**		698,891
Deferred credits and other liabilities				
Deferred income taxes		**673,939**		652,426
Regulatory liabilities		**508,877**		520,866
Employee benefit obligations		**168,387**		178,720
Other deferred credits		**122,776**		89,600
Total deferred credits and other liabilities		**1,473,979**		1,441,612
Commitments and contingencies				
Total liabilities and equity	$	**5,446,606**	$	5,468,642

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Our accompanying unaudited consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC. These statements also have been prepared in accordance with GAAP and reflect all adjustments that, in our opinion, are necessary for a fair statement of the results for the interim periods presented. All such adjustments are of a normal recurring nature. The 2018 year-end consolidated balance sheet data was derived from audited consolidated financial statements, but does not include all disclosures required by GAAP. These unaudited consolidated financial statements should be read in conjunction with the audited consolidated financial statements and footnotes in our Annual Report. Our significant accounting policies are described in Note 1 of our Notes to Consolidated Financial Statements in our Annual Report. Due to the seasonal nature of our business, the results of operations for the three and six months ended June 30, 2019 , are not necessarily indicative of the results that may be expected for a 12-month period.

We provide natural gas distribution services to our 2.2 million customers through our divisions in Oklahoma, Kansas and Texas through Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. We serve residential, commercial, industrial and transportation customers in all three states.

Use of Estimates - The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Items that may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets and liabilities, provision for doubtful accounts, unbilled revenues for natural gas delivered but for which meters have not been read, natural gas purchased but for which no invoice has been received, provision for income taxes, including any deferred tax valuation allowances, the results of litigation and various other recorded or disclosed amounts.

We evaluate these estimates on an ongoing basis using historical experience and other methods we consider reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on our financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known to us.

Segments - We operate in one reportable and operating business segment: regulated public utilities that deliver natural gas to residential, commercial, industrial and transportation customers. The accounting policies for our segment are the same as those described in Note 1 of our Notes to Consolidated Financial Statements in our Annual Report. We evaluate our financial performance principally on operating income. For the three and six months ended June 30, 2019 , and 2018 , we had no single external customer from which we received 10 percent or more of our gross revenues.

Reclassification of Prior Year Presentation - Certain prior year amounts have been reclassified for consistency with the current year presentation. Adjustments have been made to the consolidated balance sheets and consolidated statements of cash flows for the year ended December 31, 2018, to include accrued interest and accrued liabilities in other current liabilities. These reclassifications had no effect on the reported results of operations in the consolidated statements of income or previously reported cash flows from operating activities in the consolidated statements of cash flows.

Recently Issued Accounting Standards Update - In August 2018, the FASB issued ASU 2018-15, "Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract (a consensus of the FASB Emerging Issues Task Force)." Under this guidance, a company should defer implementation costs that it incurs if the company would capitalize those same costs under the internal-use software guidance for an arrangement that is a software license. This standard is effective for interim and annual periods in fiscal years beginning after December 15, 2019, and early adoption is permitted. We will adopt this standard January 1, 2020, using the prospective transition approach. We are currently assessing the potential impacts of adopting this standard, but do not expect a material impact on our consolidated financial statements.

In February 2018, the FASB issued ASU 2018-02, "Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income," which allows a reclassification from accumulated other comprehensive income (loss) to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. We adopted this new guidance in the first quarter 2019 and our adoption did not result in a material impact to our consolidated financial statements. This change is reflected in our consolidated statements of equity.

Selected Operating Information - The following tables set forth certain selected operating information for the periods indicated:

	Three Months Ended June 30,								Variances 2019 vs. 2018			
(in thousands)	2019				2018				Increase (Decrease)			
Average Number of Customers	OK	KS	TX	Total	OK	KS	TX	Total	OK	KS	TX	Total
Residential	**805**	**585**	**632**	**2,022**	798	586	624	2,008	**7**	**(1)**	**8**	**14**
Commercial and industrial	**75**	**50**	**35**	**160**	74	50	35	159	**1**	**—**	**—**	**1**
Wholesale and public authority	**—**	**—**	**3**	**3**	—	—	3	3	**—**	**—**	**—**	**—**
Transportation	**5**	**6**	**1**	**12**	5	6	1	12	**—**	**—**	**—**	**—**
Total customers	**885**	**641**	**671**	**2,197**	877	642	663	2,182	**8**	**(1)**	**8**	**15**

	Six Months Ended June 30,								Variances 2019 vs. 2018			
(in thousands)	2019				2018				Increase (Decrease)			
Average Number of Customers	OK	KS	TX	Total	OK	KS	TX	Total	OK	KS	TX	Total
Residential	**806**	**588**	**630**	**2,024**	801	588	624	2,013	**5**	**—**	**6**	**11**
Commercial and industrial	**75**	**50**	**36**	**161**	74	50	35	159	**1**	**—**	**1**	**2**
Wholesale and public authority	**—**	**—**	**3**	**3**	—	—	3	3	**—**	**—**	**—**	**—**
Transportation	**5**	**6**	**1**	**12**	5	6	1	12	**—**	**—**	**—**	**—**
Total customers	**886**	**644**	**670**	**2,200**	880	644	663	2,187	**6**	**—**	**7**	**13**

The following table reflects the total volumes delivered, excluding the effects of weather normalization mechanisms on sales volumes.

	Three Months Ended June 30,		Six Months Ended June 30,	
Volumes *(MMcf)*	**2019**	**2018**	**2019**	**2018**
Natural gas sales				
Residential	**13,417**	15,605	**79,114**	76,590
Commercial and industrial	**5,093**	5,881	**24,365**	23,871
Wholesale and public authority	**384**	355	**1,527**	1,222
Total sales volumes delivered	**18,894**	21,841	**105,006**	101,683
Transportation	**51,426**	51,770	**117,011**	116,686
Total volumes delivered	**70,320**	73,611	**222,017**	218,369

Total sales volumes delivered decreased for the three months ended June 30, 2019 , compared with the same period last year, due primarily to warmer weather in the second quarter 2019. Total sales volumes delivered increased for the six months ended June 30, 2019 , compared with the same period last year, due primarily to colder weather in the first quarter 2019. The impact of weather on residential and commercial net margin is mitigated by weather-normalization mechanisms in all jurisdictions.

The following table sets forth the HDD's in our service areas for the periods indicated:

	Three Months Ended June 30,						
	2019		2018		2019 vs. 2018	2019	2018
Heating Degree Days	Actual	Normal	Actual	Normal	Actual Variance	Actual as a percent of Normal	
Oklahoma	**188**	**191**	337	191	**(44)%**	**98%**	176%
Kansas	**342**	**396**	486	419	**(30)%**	**86%**	116%
Texas	**51**	**52**	35	54	**46 %**	**98%**	65%

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018 .
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:

Common stock, par value of $0.01	**New York Stock Exchange**
(Title of each class)	(Name of each exchange on which registered)

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 X 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 X

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 X 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 X No _

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Registration S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. _

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. (Check one) Large accelerated filer X Accelerated filer __ Non-accelerated filer __
Smaller reporting company __ Emerging growth company __

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.__

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes__ No X

The aggregate market value of the equity securities held by nonaffiliates based on the closing trade price of the registrant on June 30, 2018 , was $3.7 billion .

On February 8, 2019 , we had 52,573,267 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the definitive proxy statement to be delivered to shareholders in connection with the Annual Meeting of Shareholders to be held May 23, 2019 , are incorporated by reference in Part III.

ONE Gas, Inc.

CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2018	**2017**	**2016**
	(Thousands of dollars, except per share amounts)		
Total revenues	**$ 1,633,731**	$ 1,539,633	$ 1,427,232
Cost of natural gas	**714,636**	614,501	541,797
Operating expenses			
Operations and maintenance	**411,702**	399,290	397,315
Depreciation and amortization	**160,086**	151,889	143,829
General taxes	**58,878**	57,225	55,344
Total operating expenses	**630,666**	608,404	596,488
Operating income	**288,429**	316,728	288,947
Other expense, net	**(11,359)**	(14,525)	(19,870)
Interest expense, net	**(51,305)**	(46,065)	(43,739)
Income before income taxes	**225,765**	256,138	225,338
Income taxes	**(53,531)**	(93,143)	(85,243)
Net income	**$ 172,234**	$ 162,995	$ 140,095
Earnings per share			
Basic	**$ 3.27**	$ 3.10	$ 2.67
Diluted	**$ 3.25**	$ 3.08	$ 2.65
Average shares (*thousands*)			
Basic	**52,693**	52,527	52,453
Diluted	**53,029**	52,979	52,963
Dividends declared per share of stock	**$ 1.84**	$ 1.68	$ 1.40

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.

CONSOLIDATED BALANCE SHEETS

	December 31, 2018	December 31, 2017
Assets	(*Thousands of dollars*)	
Property, plant and equipment		
Property, plant and equipment	$ **6,073,143**	$ 5,713,912
Accumulated depreciation and amortization	**1,789,431**	1,706,327
Net property, plant and equipment	**4,283,712**	4,007,585
Current assets		
Cash and cash equivalents	**21,323**	14,413
Accounts receivable, net	**295,421**	298,768
Materials and supplies	**44,333**	39,672
Natural gas in storage	**107,295**	130,154
Regulatory assets	**54,420**	88,180
Other current assets	**20,495**	17,807
Total current assets	**543,287**	588,994
Goodwill and other assets		
Regulatory assets	**437,479**	405,189
Goodwill	**157,953**	157,953
Other assets	**46,211**	47,157
Total goodwill and other assets	**641,643**	610,299
Total assets	$ **5,468,642**	$ 5,206,878

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
CONSOLIDATED BALANCE SHEETS
(Continued)

	December 31, 2018	December 31, 2017
Equity and Liabilities	*(Thousands of dollars)*	
Equity and long-term debt		
Common stock, $0.01 par value: authorized 250,000,000 shares; issued 52,598,005 shares and outstanding 52,564,902 shares at December 31, 2018; issued 52,598,005 shares and outstanding 52,312,516 shares at December 31, 2017	$ **526**	$ 526
Paid-in capital	**1,727,492**	1,737,551
Retained earnings	**320,869**	246,121
Accumulated other comprehensive loss	**(4,086)**	(5,493)
Treasury stock, at cost: 33,103 shares at December 31, 2018 and 285,489 shares at December 31, 2017	**(2,145)**	(18,496)
Total equity	**2,042,656**	1,960,209
Long-term debt, excluding current maturities, and net of issuance costs of $11,457 and $8,033, respectively	**1,285,483**	1,193,257
Total equity and long-term debt	**3,328,139**	3,153,466
Current liabilities		
Notes payable	**299,500**	357,215
Accounts payable	**174,510**	143,681
Accrued interest	**18,924**	18,776
Accrued taxes other than income	**47,640**	41,324
Accrued liabilities	**30,294**	30,058
Regulatory liabilities	**48,394**	9,438
Customer deposits	**61,183**	60,811
Other current liabilities	**18,446**	12,027
Total current liabilities	**698,891**	673,330
Deferred credits and other liabilities		
Deferred income taxes	**652,426**	599,945
Regulatory liabilities	**520,866**	519,421
Employee benefit obligations	**178,720**	172,938
Other deferred credits	**89,600**	87,778
Total deferred credits and other liabilities	**1,441,612**	1,380,082
Commitments and contingencies		
Total liabilities and equity	$ **5,468,642**	$ 5,206,878

See accompanying Notes to Consolidated Financial Statements.

3. CREDIT FACILITY AND SHORT-TERM NOTES PAYABLE

In October 2018, we exercised a one-year extension of the ONE Gas Credit Agreement. The ONE Gas Credit Agreement remains a $700 million revolving unsecured credit facility and includes a $20 million letter of credit subfacility and a $60 million swingline subfacility. We are able to request an increase in commitments of up to an additional $500 million upon satisfaction of customary conditions, including receipt of commitments from either new lenders or increased commitments from existing lenders. The ONE Gas Credit Agreement expires in October 2023 , and is available to provide liquidity for working capital, capital expenditures, acquisitions and mergers, the issuance of letters of credit and for other general corporate purposes.

The ONE Gas Credit Agreement contains customary events of default. Upon the occurrence of certain events of default, the obligations under the ONE Gas Credit Agreement may be accelerated and the commitments may be terminated. The ONE Gas Credit Agreement also contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining ONE Gas' total debt-to-capital ratio of no more than 70 percent at the end of any calendar quarter. The ONE Gas Credit Agreement also contains customary affirmative and negative covenants, including covenants relating to liens, indebtedness of subsidiaries, investments, changes in the nature of business, fundamental changes, transactions with affiliates, burdensome agreements, and use of proceeds. In the event of a breach of certain covenants by ONE Gas, amounts outstanding under the ONE Gas Credit Agreement may become due and payable immediately. At December 31, 2018 , our total debt-to-capital ratio was 44 percent and we were in compliance with all covenants under the ONE Gas Credit Agreement.

The ONE Gas Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit rating. Based on our current credit ratings, borrowings, if any, will accrue interest at LIBOR plus 79.5 basis points, and the annual facility fee is 8 basis points.

We have a commercial paper program under which we may issue unsecured commercial paper up to a maximum amount of $700 million to fund short-term borrowing needs. The maturities of the commercial paper notes may vary but may not exceed 270 days from the date of issue. The commercial paper notes are sold generally at par less a discount representing an interest factor.

The ONE Gas Credit Agreement is available to repay the commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowing capacity under the ONE Gas Credit Agreement.

At December 31, 2018 , we had $299.5 million of commercial paper, $1.2 million in letters of credit issued under the ONE Gas Credit Agreement, with no borrowings and $399.3 million of remaining credit available under the ONE Gas Credit Agreement. The weighted-average interest rate on our commercial paper was 2.54 percent and 1.55 percent at December 31, 2018 and 2017 , respectively.

4. LONG-TERM DEBT

In November 2018, ONE Gas issued $400 million of 4.50 percent senior notes due 2048 . The proceeds from the issuance were used to retire the $300 million of 2.07 percent senior notes due 2019, to reduce the commercial paper and for general corporate purposes.

Our senior notes consist of $300 million of 3.61 percent senior notes due 2024 , $600 million of 4.658 percent senior notes due 2044 , and $400 million of 4.50 percent senior notes due 2048 . The indenture governing our Senior Notes includes an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in the aggregate principal amount of the outstanding Senior Notes to declare those senior notes immediately due and payable in full.

Depending on the series, we may redeem our Senior Notes at par, plus accrued and unpaid interest to the redemption date, starting three months, or six months, respectively, before their maturity dates. Prior to these dates, we may redeem these Senior Notes, in whole or in part, at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the respective note plus accrued and unpaid interest to the redemption date. Our Senior Notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness.

The Value Line Investment Survey

ISSUE 3
Pages 1533-1544

Value Line®

Part 2 File in page order in the *Selection & Opinion* binder. | **SELECTION & OPINION** | August 30, 2019

Dear Subscribers,

As part of our ongoing efforts to keep The Value Line Investment Survey the most valuable investment resource for our subscribers, all updated Ranks are now being released on the Value Line website by 8:00 A.M. Eastern Time on Mondays. You can access all the Ranks each week at www.valueline.com by entering your user name and password. We look forward to continuing to provide you with accurate and timely investment research. Thank you.

The Quarterly Economic Review

In This Issue

The *Selection & Opinion* Index appears in the August 16, 2019 issue on page 1564.

In Three Parts: Part 1 is the Summary & Index. This is Part 2, Selection & Opinion. Part 3 is Ratings & Reports. Volume LXXV, Number 3.

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VALUE LINE ECONOMIC AND STOCK MARKET COMMENTARY

Much has changed in the three months since our last Quarterly Economic Review, with the unsettled global situation—which had been more of an ancillary concern—fast becoming a series of headline events. True, a trade dispute with China was well under way at the time of our last in-depth look at the economy in late May. But back then, while acknowledging that "our deteriorating trade relations with China will exact a toll," we also had opined: "we sense that the respective sides will work towards a detente of some sort." Now, we are less certain, with neither combatant showing sustained efforts at compromise. Still, there have been strides in that direction recently, as the United States has decided to delay the implementation of some tariffs, to scrap others altogether, and to resume trade talks, while China has talked up the idea of compromises.

There are fewer headlines being made domestically, though here, too, concerns surface periodically. To wit, our previous forecast of 2.2% growth in the second quarter was rather prescient (as GDP gained 2.1%). Also, we said at the time that "the fundamentals appear sufficiently sound to prevent a recession this year." We are standing by that forecast. Still, the composition of that growth has changed, with less help globally, but more assistance from the Federal Reserve (in the form of a faster pace of interest-rate cuts), and stepped-up gains in consumer spending. The end result should be similar, with fairly stable growth over the next few years, interrupted by brief downdrafts and short-term growth spurts along the way.

Meanwhile, three months ago, we observed that "the spring warm up, often an annual ritual for our economy, may not take place this year." And that suggestion, too, was on the mark, to a point, as GDP growth did decelerate from 3.1% to 2.1% from the first to the second quarter. However, the components for the latter three-month span were vastly different, with the later period bringing a sharp decline in exports (reflecting our worsening trade rift with China)

Continued on page 1536

VALUE LINE FORECAST FOR THE U.S. ECONOMY

Statistical Summary for 2019-2020

	2019:2	2019:3	2019:4	2020:1	2020:2	2020:3	2020:4	2019	2020
GDP And Other Key Measures									
Real Gross Domestic Product	18925	19019	19122	19227	19327	19423	19519	18973	19374
Total Light Vehicle Sales (Mill. Units)	17.1	16.8	16.7	16.7	16.6	16.5	16.5	16.9	16.6
Housing Starts (Million Units)	1.26	1.20	1.22	1.22	1.23	1.23	1.25	1.22	1.23
After-Tax Profits ($Bill.)	1822	1941	2031	1962	2082	2019	2112	1899	2044
Annualized Rates of Change									
Gross Domestic Product (Real)	2.1	2.0	2.2	2.2	2.1	2.0	2.0	2.2	2.1
GDP Deflator	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.1	2.5
CPI-All Urban Consumers	2.9	2.5	2.4	2.0	2.0	1.9	1.8	2.2	1.9
Average For The Period									
National Unemployment Rate	3.6	3.6	3.5	3.5	3.5	3.4	3.4	3.7	3.5
Prime Rate	5.5	5.3	5.3	5.3	5.3	5.3	5.5	5.4	5.4
10-Year Treasury Note Rate	2.3	1.8	1.9	2.0	2.2	2.3	2.4	2.2	2.2

Value Line Forecast for the U.S. Economy

	Actual					Estimated				
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Gross Domestic Product and its Components (2012 Chain Weighted $) Billions of Dollars										
Final Sales	16810	17254	17659	18051	18566	*18979*	*19438*	*19807*	*20124*	*20426*
Total Consumption	11494	11922	12248	12559	12888	*13275*	*13660*	*14043*	*14408*	*14768*
Nonresidential Fixed Investment	2357	2400	2404	2538	2714	*2774*	*2851*	*2931*	*3005*	*3065*
Structures	537	521	495	518	543	*530*	*535*	*538*	*540*	*542*
Equipment & Software	1099	1133	1116	1184	1272	*1280*	*1315*	*1355*	*1395*	*1423*
Residential Fixed Investment	504	555	591	611	609	*591*	*588*	*582*	*579*	*582*
Exports	2367	2381	2378	2450	2547	*2546*	*2617*	*2669*	*2723*	*2791*
Imports	2945	3105	3164	3309	3459	*3517*	*3675*	*3859*	*4033*	*4194*
Federal Government	1183	1183	1188	1196	1228	*1270*	*1306*	*1300*	*1289*	*1276*
State & Local Governments	1848	1904	1943	1932	1948	*2023*	*2049*	*2069*	*2088*	*2104*
Gross Domestic Product	17522	18219	18707	19485	20494	*21371*	*22354*	*23348*	*24339*	*25346*
Real GDP (2012 Chain Weighted $)	16900	17387	17659	18051	18566	*18973*	*19374*	*19742*	*20078*	*20399*
Prices and Wages — Annual Rates of Change										
GDP Deflator	1.8	0.9	1.6	2.0	2.1	*2.1*	*2.5*	*2.5*	*2.5*	*2.5*
CPI-All Urban Consumers	1.6	0.4	1.8	2.1	2.2	*2.2*	*1.9*	*2.1*	*2.3*	*2.4*
PPI-Finished Goods	1.9	-3.3	1.0	3.5	2.3	*1.3*	*1.8*	*2.0*	*2.3*	*2.5*
Employment Cost Index—Total Comp.	2.1	1.9	2.2	2.6	3.0	*2.8*	*3.4*	*3.5*	*3.7*	*3.8*
Productivity	0.7	0.7	1.0	1.0	1.7	*1.9*	*1.3*	*1.3*	*1.5*	*1.7*
Production and Other Key Measures										
Industrial Prod. (% Change, Annualized)	3.7	-3.3	-0.6	3.7	4.0	*-1.0*	*0.8*	*1.2*	*1.0*	*0.8*
Factory Operating Rate (%)	75.3	75.8	74.6	75.1	76.6	*75.7*	*74.9*	*74.5*	*74.0*	*73.5*
Nonfarm Inven. Change (2012 Chain Weighted $)	65.0	127.9	28.4	27.4	50.9	*83.5*	*42.5*	*60.0*	*60.0*	*50.0*
Housing Starts (Mill. Units)	1.00	1.11	1.18	1.21	1.25	*1.22*	*1.23*	*1.25*	*1.30*	*1.25*
Existing House Sales (Mill. Units)	4.92	5.23	5.44	5.53	5.34	*5.32*	*5.46*	*5.50*	*5.45*	*5.40*
Total Light Vehicle Sales (Mill. Units)	16.4	17.4	17.5	17.2	17.2	*16.9*	*16.6*	*16.5*	*16.4*	*16.2*
National Unemployment Rate (%)	6.2	5.3	4.9	4.4	3.9	*3.7*	*3.5*	*3.5*	*3.6*	*3.8*
Federal Budget Surplus (Unified, FY, $Bill)	-483	-479	-582	-681	-873	*-1078*	*-1100*	*-1200*	*-1250*	*-1300*
Price of Oil ($Bbl., U.S. Refiners' Cost)	92.23	48.40	40.60	50.69	64.44	*58.75*	*58.25*	*58.00*	*60.00*	*62.00*
Money and Interest Rates										
3-Month Treasury Bill Rate (%)	0.1	0.1	0.3	0.9	1.9	*2.2*	*2.0*	*2.2*	*2.2*	*2.3*
Federal Funds Rate (%)	0.1	0.1	0.4	1.0	1.8	*2.3*	*2.2*	*2.4*	*2.4*	*2.5*
10-Year Treasury Note Rate (%)	2.5	2.2	1.9	2.3	2.9	*2.2*	*2.2*	*2.8*	*3.0*	*3.3*
Long-Term Treasury Bond Rate (%)	3.3	2.9	2.6	2.9	3.1	*2.6*	*2.6*	*3.3*	*3.5*	*3.6*
AAA Corporate Bond Rate (%)	4.2	3.9	3.7	3.8	3.9	*3.4*	*3.5*	*3.7*	*3.8*	*4.0*
Prime Rate (%)	3.3	3.3	3.5	4.1	4.9	*5.4*	*5.4*	*5.5*	*5.5*	*5.7*
Incomes										
Personal Income (Annualized % Change)	4.4	3.8	3.0	4.6	4.6	*4.9*	*4.5*	*4.8*	*4.5*	*4.5*
Real Disp. Inc. (Annualized % Change)	2.7	3.1	1.6	2.8	3.3	*2.7*	*2.8*	*2.5*	*2.2*	*2.0*
Personal Savings Rate (%)	4.8	7.6	6.7	6.7	6.8	*8.1*	*7.8*	*7.0*	*7.0*	*6.0*
After-Tax Profits (Annualized $Bill)	1694	1737	1737	1782	1854	*1899*	*2044*	*2146*	*2232*	*2299*
Yr-to-Yr % Change	0.1	2.5	0.0	2.6	4.1	*2.4*	*7.7*	*5.0*	*4.0*	*3.0*
Composition of Real GDP-Annual Rates of Change										
Gross Domestic Product	2.5	2.9	1.6	2.2	2.9	*2.2*	*2.1*	*1.9*	*1.7*	*1.6*
Final Sales	1.9	2.6	2.4	2.2	2.7	*2.2*	*2.4*	*1.9*	*1.6*	*1.5*
Total Consumption	2.9	3.7	2.7	2.5	2.6	*3.0*	*2.9*	*2.8*	*2.6*	*2.5*
Nonresidential Fixed Investment	6.9	1.8	0.2	5.6	6.9	*2.2*	*2.8*	*2.8*	*2.5*	*2.0*
Structures	10.6	-3.0	-5.0	4.6	4.9	*-2.3*	*1.0*	*0.5*	*0.3*	*0.5*
Equipment & Software	6.7	3.1	-1.5	6.1	7.5	*0.7*	*2.7*	*3.0*	*3.0*	*2.0*
Residential Fixed Investment	3.8	10.1	6.5	3.4	-0.3	*-2.9*	*-0.5*	*-1.0*	*-0.5*	*0.5*
Exports	4.3	0.6	-0.1	3.0	4.0	*0.0*	*2.8*	*2.0*	*2.0*	*2.5*
Imports	5.1	5.5	1.9	4.6	4.5	*1.7*	*4.5*	*5.0*	*4.5*	*4.0*
Federal Government	-2.6	0.0	0.4	0.7	2.6	*3.4*	*2.9*	*-0.5*	*-0.8*	*-1.0*
State & Local Governments	0.2	3.0	2.0	-0.5	0.8	*3.9*	*1.2*	*1.0*	*0.9*	*0.8*

BLUE CHIP FINANCIAL FORECASTS

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them.

Vol. 38 No. 6
June 1, 2019

Wolters Kluwer

Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2021 through 2025 and averages for the five-year periods 2021-2025 and 2026-2030. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
		2021	2022	2023	2024	2025	2021-2025	2026-2030
1. Federal Funds Rate	CONSENSUS	**2.4**	**2.4**	**2.6**	**2.7**	**2.8**	**2.6**	**2.8**
	Top 10 Average	3.1	3.2	3.4	3.4	3.4	3.3	3.4
	Bottom 10 Average	1.5	1.6	1.7	2.1	2.2	1.8	2.1
2. Prime Rate	CONSENSUS	**5.4**	**5.5**	**5.6**	**5.8**	**5.8**	**5.6**	**5.7**
	Top 10 Average	6.1	6.2	6.4	6.4	6.4	6.3	6.2
	Bottom 10 Average	4.6	4.7	4.8	5.1	5.3	4.9	5.1
3. LIBOR, 3-Mo.	CONSENSUS	**2.7**	**2.8**	**2.8**	**3.0**	**3.0**	**2.9**	**3.0**
	Top 10 Average	3.3	3.4	3.6	3.6	3.6	3.5	3.6
	Bottom 10 Average	2.1	2.1	2.0	2.4	2.5	2.2	2.5
4. Commercial Paper, 1-Mo.	CONSENSUS	**2.5**	**2.6**	**2.7**	**2.9**	**2.9**	**2.7**	**2.9**
	Top 10 Average	3.1	3.2	3.4	3.4	3.5	3.3	3.4
	Bottom 10 Average	2.0	2.0	2.0	2.4	2.4	2.2	2.4
5. Treasury Bill Yield, 3-Mo.	CONSENSUS	**2.4**	**2.4**	**2.5**	**2.7**	**2.8**	**2.6**	**2.8**
	Top 10 Average	3.1	3.2	3.4	3.4	3.4	3.3	3.4
	Bottom 10 Average	1.5	1.6	1.7	2.0	2.2	1.8	2.1
6. Treasury Bill Yield, 6-Mo.	CONSENSUS	**2.4**	**2.5**	**2.7**	**2.9**	**2.9**	**2.7**	**2.9**
	Top 10 Average	3.1	3.3	3.5	3.5	3.5	3.4	3.5
	Bottom 10 Average	1.7	1.7	1.8	2.2	2.4	2.0	2.3
7. Treasury Bill Yield, 1-Yr.	CONSENSUS	**2.5**	**2.6**	**2.8**	**3.0**	**3.0**	**2.8**	**3.0**
	Top 10 Average	3.3	3.4	3.6	3.6	3.7	3.5	3.7
	Bottom 10 Average	1.8	1.8	2.0	2.3	2.4	2.0	2.3
8. Treasury Note Yield, 2-Yr.	CONSENSUS	**2.6**	**2.7**	**2.9**	**3.0**	**3.1**	**2.9**	**3.1**
	Top 10 Average	3.3	3.5	3.7	3.8	3.8	3.6	3.8
	Bottom 10 Average	1.8	1.9	2.0	2.3	2.4	2.1	2.3
10. Treasury Note Yield, 5-Yr.	CONSENSUS	**2.8**	**2.9**	**3.1**	**3.2**	**3.3**	**3.0**	**3.3**
	Top 10 Average	3.5	3.7	4.0	4.0	4.0	3.8	4.1
	Bottom 10 Average	2.0	2.1	2.2	2.3	2.5	2.2	2.4
11. Treasury Note Yield, 10-Yr.	CONSENSUS	**3.0**	**3.1**	**3.3**	**3.3**	**3.4**	**3.2**	**3.4**
	Top 10 Average	3.6	3.9	4.2	4.2	4.2	4.0	4.4
	Bottom 10 Average	2.3	2.4	2.4	2.5	2.6	2.4	2.6
12. Treasury Bond Yield, 30-Yr.	CONSENSUS	**3.3**	**3.5**	**3.6**	**3.7**	**3.8**	**3.6**	**3.8**
	Top 10 Average	4.0	4.3	4.5	4.6	4.6	4.4	4.8
	Bottom 10 Average	2.7	2.7	2.8	2.9	2.9	2.8	2.9
13. Corporate Aaa Bond Yield	CONSENSUS	**4.4**	**4.6**	**4.7**	**4.7**	**4.8**	**4.6**	**4.8**
	Top 10 Average	5.0	5.2	5.5	5.5	5.5	5.3	5.6
	Bottom 10 Average	3.8	3.9	3.9	4.0	4.0	3.9	4.0
13. Corporate Baa Bond Yield	CONSENSUS	**5.3**	**5.6**	**5.7**	**5.7**	**5.7**	**5.6**	**5.8**
	Top 10 Average	6.0	6.3	6.6	6.6	6.7	6.5	6.8
	Bottom 10 Average	4.7	4.8	4.7	4.8	4.8	4.7	4.8
14. State & Local Bonds Yield	CONSENSUS	**4.1**	**4.2**	**4.3**	**4.3**	**4.3**	**4.2**	**4.4**
	Top 10 Average	4.6	4.9	5.0	5.0	5.0	4.9	5.1
	Bottom 10 Average	3.5	3.6	3.6	3.6	3.6	3.6	3.6
15. Home Mortgage Rate	CONSENSUS	**4.7**	**4.8**	**4.9**	**5.0**	**5.0**	**4.9**	**5.0**
	Top 10 Average	5.3	5.5	5.8	5.8	5.8	5.6	5.9
	Bottom 10 Average	4.0	4.0	4.0	4.2	4.2	4.1	4.2
A. Fed's AFE Nominal $ Index	CONSENSUS	**108.5**	**108.2**	**108.0**	**107.6**	**106.9**	**107.8**	**106.7**
	Top 10 Average	110.8	110.5	110.9	110.8	110.6	110.7	111.2
	Bottom 10 Average	106.6	105.8	104.9	104.6	103.6	105.1	102.9
		Year-Over-Year, % Change					**Five-Year Averages**	
		2021	**2022**	**2023**	**2024**	**2025**	**2021-2025**	**2026-2030**
B. Real GDP	CONSENSUS	**1.9**	**1.9**	**2.0**	**2.1**	**2.1**	**2.0**	**2.1**
	Top 10 Average	2.3	2.4	2.4	2.5	2.5	2.4	2.6
	Bottom 10 Average	1.5	1.4	1.6	1.8	1.8	1.6	1.8
C. GDP Chained Price Index	CONSENSUS	**2.1**	**2.1**	**2.0**	**2.0**	**2.0**	**2.1**	**2.0**
	Top 10 Average	2.4	2.4	2.2	2.2	2.2	2.3	2.2
	Bottom 10 Average	1.8	1.8	1.8	1.9	1.9	1.9	1.8
D. Consumer Price Index	CONSENSUS	**2.1**	**2.2**	**2.2**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.5	2.4	2.4	2.4	2.4	2.4	2.4
	Bottom 10 Average	1.7	1.8	1.9	1.9	1.9	1.8	1.8

Moody's
INVESTORS SERVICE

Rating Action: Moody's affirms ONE Gas at A2, revises outlook to stable from negative

28 Jan 2019

Approximately $1.3 billion of debt affected

New York, January 28, 2019 -- Moody's Investors Service ("Moody's") today affirmed the ratings of ONE Gas, Inc (ONE Gas), including its A2 senior unsecured rating and P-1 commercial paper rating. At the same time, Moody's revised the rating outlook to stable from negative.

Outlook Actions:

..Issuer: ONE Gas, Inc

....Outlook, Changed To Stable From Negative

Affirmations:

..Issuer: ONE Gas, Inc

....Senior Unscured Shelf, Affirmed (P)A2

....Senior Unsecured Commercial Paper, Affirmed P-1

....Senior Unsecured Regular Bond/Debenture, Affirmed A2

RATINGS RATIONALE

"ONE Gas' financial metrics will remain steady over the next few years thanks to corporate actions to mitigate the negative impacts of tax reform and improved recovery of eligible system investments allowed in Kansas" stated Nana Hamilton, Analyst.

The change in rating outlook to stable from negative reflects corporate actions that ONE Gas has taken to strengthen its balance sheet and key financial ratios. For example, ONE Gas adjusted the timing of its projected debt issuances and has introduced plans to issue new equity as part of its financing plan. Furthermore, ONE Gas has terminated its share buy-back program and Moody's expects dividend increases over the next few years will be at the lower end of the company stated 7%-9% rate of increase. The corporate dividend policy is still a credit negative, in the sense that dividend growth appears higher than earnings growth, and the ratio of retained cash flow to debt is calculated to remain in the mid-teen's range over the next few years, reflecting the Baa-rating category in our rating methodology grid.

In addition, Moody's thinks Kansas bill SB 279, enacted in June 2018, will result in improved recovery of infrastructure spend in the state, a credit positive. The bill amended the Gas Safety Reliability Policy Act which governs the utility's gas safety reliability surcharges (GSRS) mechanism. The new bill allows gas utilities to recover costs for eligible infrastructure system investments and not only infrastructure system replacements per previous law. Furthermore, the bill increases the amount of GSRS that may be approved by the Kansas commission from 10% up to 20% of the utility's base revenue as determined in the most recent general rate proceeding. The bill also raises the cap on the GSRS monthly charge from $0.40 to $0.80 per residential customer over the base rates in effect for the initial filing and each subsequent filing.

ONE Gas' A2 unsecured rating primarily reflects the company's low business risk profile as a fully regulated Local Distribution Company (LDC). ONE Gas operates in the credit supportive regulatory jurisdictions of Oklahoma, Kansas and Texas, with substantial fixed fee rates and an attractive suite of rider recovery mechanisms that support predictable revenue and cash flow generation. In addition, the company's proximity to significant natural gas reserves provides access to long-term low-cost natural gas supply. These strengths are somewhat offset by a significant capital investment program and credit metrics which, while expected to remain stable, are on the weak end of the acceptable range for the rating. Over the next two years, the company plans to spend over $400 million per year in capex, relative to about $300 million on average historically, and Moody's projects cash flow from operations before changes in working capital (CFO pre-WC) to debt around 20%.

Outlook

ONE Gas' stable rating outlook is predicated on the utility's ability to keep generating consistent and predictable operating cash flows; the continued supportiveness of its three state regulators; conservative financing policies; and the maintenance of relatively weak but sustained debt coverage ratios, including CFO pre-WC to debt around 20%.

What could change the rating -- UP

A rating upgrade could be considered if ONE Gas experiences greater regulatory supportiveness such that financial metrics improve, including CFO pre-WC to debt above 25%, on a sustained basis

What could change the rating -- DOWN

A downgrade could be considered if there is a significant decline in the support provided by the utility's regulators or if the company decides to adopt a more aggressive dividend payout policy at the same time as it executes on its elevated capex program or if there is a deterioration in financial metrics, including CFO pre-WC to debt below 20% for an extended period.

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in June 2017. Please see the Rating Methodologies page on www.moodys.com for a copy of this methodology.

REGULATORY DISCLOSURES

For ratings issued on a program, series or category/class of debt, this announcement provides certain regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides certain regulatory disclosures in relation to the credit rating action on the support provider and in relation to each particular credit rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides certain regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

For any affected securities or rated entities receiving direct credit support from the primary entity(ies) of this credit rating action, and whose ratings may change as a result of this credit rating action, the associated regulatory disclosures will be those of the guarantor entity. Exceptions to this approach exist for the following disclosures, if applicable to jurisdiction: Ancillary Services, Disclosure to rated entity, Disclosure from rated entity.

Regulatory disclosures contained in this press release apply to the credit rating and, if applicable, the related rating outlook or rating review.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

Please see the ratings tab on the issuer/entity page on www.moodys.com for additional regulatory disclosures for each credit rating.

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Asst Vice President - Analyst
Infrastructure Finance Group
Moody's Investors Service, Inc.
250 Greenwich Street
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U.S.A.

NATURAL GAS (DISTRIBUTION) INDUSTRY

LDC INDUSTRY GROUP

IDENTIFIABLE ASSETS - Most Recent Fiscal Year-end (b)

	Company (a)	GAS UTILITY	%	TOTAL	INCLUDED/EXCLUDED	FISCAL YEAR-END
1	Atmos Energy	11,109	78.9%	14,073	Included	9/30
2	Chesapeake Utilities	1,346	79.5%	1,694	Included	12/31
3	New Jersey Resources	2,663	62.2%	4,282	Included	9/30
4	NiSource, Inc.	13,527	70.2%	19,262	Included	12/31
5	Northwest Natural Gas	3,193	90.5%	3,229	Included	12/31
6	ONE Gas	1	100.0%	1	Included	12/31
7	South Jersey Industries	5,283	90.0%	5,869	Included	12/31
8	Southwest Gas	6,142	83.5%	7,358	Included	12/31
9	Spire	5,607	66.7%	8,410	Included	9/30
10	UGI	3,267	27.6%	11,855	Excluded -- Assets	9/30

(a) *The Value Line Investment Survey* (August 30, 2019).
(b) 2018 Forms 10-K.

ONE GAS INC.
COST OF DEBT

	June 30, 2019		
Description	**Amount**	**Rate**	**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
4.50% due 2048	400,000,000	4.50%	18,000,000
Debt Issuance	(11,158,720)		439,004
Debt Retirement	(6,893,627)		810,713
Total	**1,281,947,653**		**58,027,717**
Cost of Debt		**4.53%**	

Unamortized issuance cost balance:

Natural	Description	December 2017 Balance
2240311	LT DEBT ISSUANCE COST 2.07% DUE 2019	$ 329,750.57
2240312	LT DEBT ISSUANCE COST 3.61% DUE 2024	$ 1,614,276.82
2240313	LT DEBT ISSUANCE COST 4.658% DUE 2044	$ 5,888,615.45
		$ 8,032,650.84

Debt balances

Natural	Description	December 2017 Balance
1890110	UNAMORT LOSS REACQ DEBT 8.7% D	$ 333,540.79
1890118	UNAMORT LOSS REACQ 6 7/8%	$ 4,142,288.09
1890119	UNAMORT LOSS REACQ DEBT 6.125%	$ 3,531,847.84
2240211	LT PRIN DUE 2.07% DUE 2019	$ 300,000,000.00
2240212	LT PRIN DUE 3.61% DUE 2024	$ 200,000,000.00
2240213	LT PRIN DUE 4.658% DUE 2044	$ 600,000,000.00

2017 amortization expense:

Natural	Description	Monthly Entry	
2240311	Amortize Debt Discount - January	$ (38,891.00)	
2240311	Amortize Debt Discount - February	$ (39,325.31)	
2240311	Amortize Debt Discount - March	$ (39,325.31)	
2240311	Amortize Debt Discount - April	$ (39,325.31)	
2240311	Amortize Debt Discount - May	$ (39,325.31)	
2240311	Amortize Debt Discount - June	$ (39,325.31)	
2240311	Amortize Debt Discount - July	$ (39,325.31)	
2240311	Amortize Debt Discount - August	$ (39,764.67)	
2240311	Amortize Debt Discount - September	$ (39,764.67)	
2240311	Amortize Debt Discount - October	$ (39,764.67)	
2240311	Amortize Debt Discount - November	$ (39,764.67)	
2240311	Amortize Debt Discount - December	$ (39,764.67)	
		$ (473,060.21)	2017 Total
2240312	Amortize Debt Discount - January	$ (18,801.54)	
2240312	Amortize Debt Discount - February	$ (19,206.41)	
2240312	Amortize Debt Discount - March	$ (19,206.41)	
2240312	Amortize Debt Discount - April	$ (19,206.41)	
2240312	Amortize Debt Discount - May	$ (19,206.41)	
2240312	Amortize Debt Discount - June	$ (19,206.41)	
2240312	Amortize Debt Discount - July	$ (19,206.41)	
2240312	Amortize Debt Discount - August	$ (19,562.62)	
2240312	Amortize Debt Discount - September	$ (19,562.62)	
2240312	Amortize Debt Discount - October	$ (19,562.62)	
2240312	Amortize Debt Discount - November	$ (19,562.62)	
2240312	Amortize Debt Discount - December	$ (19,562.62)	
		$ (231,603.10)	2017 Total
2240313	Amortize Debt Discount - January	$ (9,084.02)	
2240313	Amortize Debt Discount - February	$ (9,319.82)	
2240313	Amortize Debt Discount - March	$ (9,319.82)	
2240313	Amortize Debt Discount - April	$ (9,319.82)	
2240313	Amortize Debt Discount - May	$ (9,319.82)	
2240313	Amortize Debt Discount - June	$ (9,319.82)	
2240313	Amortize Debt Discount - July	$ (9,319.82)	
2240313	Amortize Debt Discount - August	$ (9,539.94)	
2240313	Amortize Debt Discount - September	$ (9,539.94)	
2240313	Amortize Debt Discount - October	$ (9,539.94)	
2240313	Amortize Debt Discount - November	$ (9,539.94)	
2240313	Amortize Debt Discount - December	$ (9,539.94)	
		$ (112,702.64)	2017 Total

Unamortized issuance cost balance:

Natural	Description	December 2018 Balance
2240311	LT DEBT ISSUANCE COST 2.07% DUE 2019	$ -
2240312	LT DEBT ISSUANCE COST 3.61% DUE 2024	$ 1,373,668.50
2240313	LT DEBT ISSUANCE COST 4.658% DUE 2044	$ 5,710,504.45
2240314	LT DEBT ISSUANCE COST 4.5% DUE 2048	$ 4,312,518.07
		$ 11,496,711.02

Debt balances

Natural	Description	December 2018 Balance
1890110	UNAMORT LOSS REACQ DEBT 8.7% D	$ 294,923.07
1890118	UNAMORT LOSS REACQ 6 7/8%	$ 3,756,958.87
1890119	UNAMORT LOSS REACQ DEBT 6.125%	$ 3,294,001.73
2240211	LT PRIN DUE 2.07% DUE 2019	$ -
2240212	LT PRIN DUE 3.61% DUE 2024	$ 300,000,000.00
2240213	LT PRIN DUE 4.658% DUE 2044	$ 600,000,000.00
2240214	LT PRIN DUE 4.5% DUE 2048	$ 400,000,000.00

2018 amortization expense:

Natural	Description	Monthly Entry	
2240311	Amortize Debt Discount - January	$ 33,764.67	
2240311	Amortize Debt Discount - February	$ 40,208.93	
2240311	Amortize Debt Discount - March	$ 40,208.93	
2240311	Amortize Debt Discount - April	$ 40,208.93	
2240311	Amortize Debt Discount - May	$ 40,208.93	
2240311	Amortize Debt Discount - June	$ 40,208.93	
2240311	Amortize Debt Discount - July	$ 40,208.93	
2240311	Amortize Debt Discount - August	$ 40,658.15	
2240311	Amortize Debt Discount - September	$ 40,658.15	
2240311	Amortize Debt Discount - October	$ 40,658.15	
2240311	Amortize Debt Discount - November	$ 120,763.87	
2240311	Amortize Debt Discount - December	$ -	
		$ 529,756.55	2018 Total
2240312	Amortize Debt Discount - January	$ 19,562.62	
2240312	Amortize Debt Discount - February	$ 19,925.45	
2240312	Amortize Debt Discount - March	$ 19,925.45	
2240312	Amortize Debt Discount - April	$ 19,925.45	
2240312	Amortize Debt Discount - May	$ 19,925.45	
2240312	Amortize Debt Discount - June	$ 19,925.45	
2240312	Amortize Debt Discount - July	$ 19,925.45	
2240312	Amortize Debt Discount - August	$ 20,295.00	
2240312	Amortize Debt Discount - September	$ 20,295.00	
2240312	Amortize Debt Discount - October	$ 20,295.00	
2240312	Amortize Debt Discount - November	$ 20,295.00	
2240312	Amortize Debt Discount - December	$ 20,295.00	
		$ 240,590.34	2018 Total
2240313	Amortize Debt Discount - January	$ 9,539.94	
2240313	Amortize Debt Discount - February	$ 9,765.26	
2240313	Amortize Debt Discount - March	$ 9,765.26	
2240313	Amortize Debt Discount - April	$ 9,765.26	
2240313	Amortize Debt Discount - May	$ 9,765.26	
2240313	Amortize Debt Discount - June	$ 9,765.26	
2240313	Amortize Debt Discount - July	$ 9,765.26	
2240313	Amortize Debt Discount - August	$ 9,995.90	
2240313	Amortize Debt Discount - September	$ 9,995.90	
2240313	Amortize Debt Discount - October	$ 9,995.90	
2240313	Amortize Debt Discount - November	$ 9,995.90	
2240313	Amortize Debt Discount - December	$ 9,995.96	
		$ 118,111.03	2018 Total
2240313	Amortize Debt Discount - January	$ -	
2240313	Amortize Debt Discount - February	$ -	
2240313	Amortize Debt Discount - March	$ -	
2240313	Amortize Debt Discount - April	$ -	
2240313	Amortize Debt Discount - May	$ -	
2240313	Amortize Debt Discount - June	$ -	
2240313	Amortize Debt Discount - July	$ -	
2240313	Amortize Debt Discount - August	$ -	
2240313	Amortize Debt Discount - September	$ -	
2240313	Amortize Debt Discount - October	$ -	
2240313	Amortize Debt Discount - November	$ 5,647.19	
2240313	Amortize Debt Discount - December	$ 5,647.19	
		$ 11,294.38	2018 Total

Unamortized issuance cost balance:

Natural	Description	June 2019 Balance
2240311	LT DEBT ISSUANCE COST 2.07% DUE 2019	$ -
2240312	LT DEBT ISSUANCE COST 3.61% DUE 2024	$ 1,250,036.45
2240313	LT DEBT ISSUANCE COST 4.658% DUE 2044	$ 5,703,349.55
2240314	LT DEBT ISSUANCE COST 4.5% DUE 2048	$ 4,158,335.09
		$ 11,168,720.09

Debt balances

Natural	Description	June 2019 Balance
1890110	UNAMORT LOSS REACQ DEBT 8.7% D	$ 204,254.21
1890118	UNAMORT LOSS REACQ 6 7/8%	$ 3,564,294.41
1890119	UNAMORT LOSS REACQ DEBT 6.125%	$ 3,125,078.59
2240211	LT PRIN DUE 2.07% DUE 2019	$ -
2240212	LT PRIN DUE 3.61% DUE 2024	$ 300,000,000.00
2240213	LT PRIN DUE 4.658% DUE 2044	$ 600,000,000.00
2240214	LT PRIN DUE 4.5% DUE 2048	$ 400,000,000.00

6-months 2019	Annualized 2019	Check
$ 43,768.86	$ 87,537.72	$ 87,537.72
$ 192,664.56	$ 385,329.12	$ 385,329.12
$ 168,923.04	$ 337,846.08	$ 337,846.08

2019 actual and anticipated amortization expense:

Natural	Description	Monthly Entry	
2240311	Amortize Debt Discount - January	$ -	
2240311	Amortize Debt Discount - February	$ -	
2240311	Amortize Debt Discount - March	$ -	
2240311	Amortize Debt Discount - April	$ -	
2240311	Amortize Debt Discount - May	$ -	
2240311	Amortize Debt Discount - June	$ -	
2240311	Amortize Debt Discount - July	$ -	
2240311	Amortize Debt Discount - August	$ -	
2240311	Amortize Debt Discount - September	$ -	
2240311	Amortize Debt Discount - October	$ -	
2240311	Amortize Debt Discount - November	$ -	
2240311	Amortize Debt Discount - December	$ -	
		$ -	2019 Total <--note paid off in 2018
2240312	Amortize Debt Discount - January	$ 20,295.00	
2240312	Amortize Debt Discount - February	$ 20,671.41	
2240312	Amortize Debt Discount - March	$ 20,671.41	
2240312	Amortize Debt Discount - April	$ 20,671.41	
2240312	Amortize Debt Discount - May	$ 20,671.41	
2240312	Amortize Debt Discount - June	$ 20,671.41	
2240312	Amortize Debt Discount - July	$ 20,671.41	
2240312	Amortize Debt Discount - August	$ 21,054.80	
2240312	Amortize Debt Discount - September	$ 21,054.80	
2240312	Amortize Debt Discount - October	$ 21,054.80	
2240312	Amortize Debt Discount - November	$ 21,054.80	
2240312	Amortize Debt Discount - December	$ 21,054.80	
		$ 248,597.45	2019 Total
2240313	Amortize Debt Discount - January	$ 9,995.90	
2240313	Amortize Debt Discount - February	$ 10,232.00	
2240313	Amortize Debt Discount - March	$ 10,232.00	
2240313	Amortize Debt Discount - April	$ 10,232.00	
2240313	Amortize Debt Discount - May	$ 10,232.00	
2240313	Amortize Debt Discount - June	$ 10,232.00	
2240313	Amortize Debt Discount - July	$ 10,232.00	
2240313	Amortize Debt Discount - August	$ 10,473.66	
2240313	Amortize Debt Discount - September	$ 10,473.66	
2240313	Amortize Debt Discount - October	$ 10,473.66	
2240313	Amortize Debt Discount - November	$ 10,473.66	
2240313	Amortize Debt Discount - December	$ 10,473.66	
		$ 123,756.21	2019 Total
2240313	Amortize Debt Discount - January	$ 5,647.19	
2240313	Amortize Debt Discount - February	$ 5,647.19	
2240313	Amortize Debt Discount - March	$ 5,647.19	
2240313	Amortize Debt Discount - April	$ 5,673.76	
2240313	Amortize Debt Discount - May	$ 5,680.23	
2240313	Amortize Debt Discount - June	$ 5,680.23	
2240313	Amortize Debt Discount - July	$ 5,680.23	
2240313	Amortize Debt Discount - August	$ 5,680.23	
2240313	Amortize Debt Discount - September	$ 5,680.23	
2240313	Amortize Debt Discount - October	$ 5,680.23	
2240313	Amortize Debt Discount - November	$ 5,811.82	
2240313	Amortize Debt Discount - December	$ 5,811.82	
		$ 67,720.35	2019 Total

THE VALUE LINE
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Part 3
Ratings & Reports

ISSUE 3
Pages 500-650
File in the binder in order of issue number, removing previous issue bearing the same number.

August 30, 2019

ESPECIALLY NOTEWORTHY:

*This week, a couple of pipeline companies join the ranks of the Value Line Investment Survey. **Antero Midstream** and **EnLink Midstream** come on board in the Oil/Gas Distribution Industry on pages 609 and 613, respectively.*

*Uneven oil prices have created value in some big-name petroleum issues, such as France's **Total**. Page 521.*

*The good-quality shares of natural gas utility **South Jersey Industries** (page 554) should prove a nice fit for investors in search of steady income and dividend growth.*

***Ecolab's** earnings engine continues to hum along. Check out the water and food safety specialist's prospects on page 567.*

*Chemical Industry component **W.R. Grace** appears well positioned to boost profits over the long haul. See page 572 for an update.*

***Enbridge Inc.'s** pipeline business has solid growth potential with the ongoing development of shale reserves in North America. Turn to page 612 for more.*

★★ 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 LXXV, No. 3
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ATMOS ENERGY CORP. NYSE-ATO

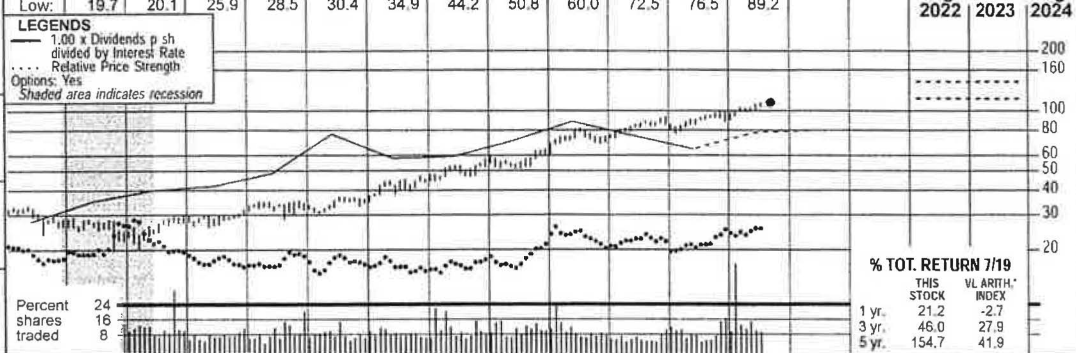
RECENT PRICE 110.21 | P/E RATIO 25.2 (Trailing: 25.7 Median: 16.0) | RELATIVE P/E RATIO 1.54 | DIV'D YLD 2.0% | VALUE LINE

TIMELINESS 3 Lowered 11/30/18
SAFETY 1 Raised 6/6/14
TECHNICAL 3 Lowered 7/5/19
BETA .60 (1.00 = Market)

High:	29.3	30.3	32.0	35.6	37.3	47.4	58.2	64.8	82.0	93.6	100.8	111.4
Low:	19.7	20.1	25.9	28.5	30.4	34.9	44.2	50.8	60.0	72.5	76.5	89.2

Target Price Range 2022 | 2023 | 2024

LEGENDS
—— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	140	(+25%)	8%
Low	115	(+5%)	3%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	2	8	0	2	0	0	2	8	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	185	232	243
to Sell	175	177	204
Hld's(000)	82454	92261	96087

Percent shares traded 24 16 8

% TOT. RETURN 7/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.2	-2.7
3 yr.	46.0	27.9
5 yr.	154.7	41.9

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	*24.30*	*24.95*	Revenues per sh A	*37.95*
4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	*7.50*	*7.80*	"Cash Flow" per sh	*9.20*
1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	*4.30*	*4.55*	Earnings per sh AB	*5.60*
1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	*2.10*	*2.24*	Div'ds Decl'd per sh C■	*2.70*
5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	*14.15*	*14.40*	Cap'l Spending per sh	*13.80*
23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	*47.65*	*48.90*	Book Value per sh	*56.05*
92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	*120.00*	*125.00*	Common Shs Outst'g D	*145.00*
12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	*Bold figures are*		Avg Ann'l P/E Ratio	*23.0*
.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	*Value Line*		Relative P/E Ratio	*1.30*
5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	*estimates*		Avg Ann'l Div'd Yield	*2.1%*
4969.1	4789.7	4347.6	3438.5	3886.3	4940.9	4142.1	3349.9	2759.7	3115.5	*2915*	*3120*	Revenues ($mill) A	*5500*
179.7	201.2	199.3	192.2	230.7	289.8	315.1	350.1	382.7	444.3	*515*	*570*	Net Profit ($mill)	*815*
34.4%	38.5%	36.4%	33.8%	38.2%	39.2%	38.3%	36.4%	36.6%	27.0%	*22.0%*	*22.5%*	Income Tax Rate	*24.0%*
3.6%	4.2%	4.6%	5.6%	5.9%	5.9%	7.6%	10.5%	13.9%	14.3%	*17.7%*	*18.3%*	Net Profit Margin	*14.8%*
49.9%	45.4%	49.4%	45.3%	48.8%	44.3%	43.5%	38.7%	44.0%	34.3%	*38.5%*	*37.0%*	Long-Term Debt Ratio	*35.0%*
50.1%	54.6%	50.6%	54.7%	51.2%	55.7%	56.5%	61.3%	56.0%	65.7%	*61.5%*	*63.0%*	Common Equity Ratio	*65.0%*
4346.2	3987.9	4461.5	4315.5	5036.1	5542.2	5650.2	5651.8	6965.7	7263.6	*9300*	*9700*	Total Capital ($mill)	*12500*
4439.1	4793.1	5147.9	5475.6	6030.7	6725.9	7430.6	8280.5	9259.2	10371	*11500*	*12600*	Net Plant ($mill)	*15800*
5.9%	6.9%	6.1%	6.1%	5.9%	6.4%	6.6%	7.2%	6.4%	6.9%	*6.5%*	*7.0%*	Return on Total Cap'l	*7.5%*
8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.0%*
8.3%	9.2%	8.8%	8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	*9.0%*	*9.5%*	Return on Com Equity	*10.0%*
2.7%	3.5%	3.3%	2.8%	4.0%	4.7%	4.9%	5.1%	4.9%	4.8%	*4.5%*	*5.0%*	Retained to Com Eq	*5.0%*
68%	62%	62%	65%	56%	50%	51%	50%	50%	48%	*49%*	*49%*	All Div'ds to Net Prof	*48%*

CAPITAL STRUCTURE as of 6/30/19
Total Debt $3729.0 mill. **Due in 5 Yrs** $1150.0 mill.
LT Debt $3529.1 mill. **LT Interest** $200.0 mill.
(LT interest earned: 6.7x; total interest coverage: 6.7x)
Leases, Uncapitalized Annual rentals $17.7 mill.
Pfd Stock None
Pension Assets-9/18 $531.7 mill. **Oblig.** $504.7 mill.
Common Stock 118,200,689 shs. as of 7/31/19
MARKET CAP: $13.0 billion (Large Cap)

CURRENT POSITION ($MILL.)	2017	2018	6/30/19
Cash Assets	26.4	13.8	46.2
Other	513.2	465.1	457.3
Current Assets	539.6	478.9	503.5
Accts Payable	233.0	217.3	206.5
Debt Due	447.7	1150.8	199.9
Other	332.7	547.0	495.0
Current Liab.	1013.4	1915.1	901.4
Fix. Chg. Cov.	805%	926%	915%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-9.0%	-8.0%	*5.0%*
"Cash Flow"	5.0%	6.5%	*5.5%*
Earnings	6.5%	10.0%	*7.5%*
Dividends	3.5%	5.5%	*7.0%*
Book Value	5.5%	7.0%	*7.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2016	906.2	1132.3	632.9	678.5	3349.9
2017	780.2	988.2	526.5	464.8	2759.7
2018	889.2	1219.4	562.2	444.7	3115.5
2019	877.8	1094.6	485.7	*456.9*	*2915*
2020	*900*	*1150*	*600*	*470*	*3120*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2016	1.00	1.38	.69	.33	3.38
2017	1.08	1.52	.67	.34	3.60
2018	1.40	1.57	.64	.41	4.00
2019	1.38	1.82	.68	*.42*	*4.30*
2020	*1.48*	*1.80*	*.77*	*.50*	*4.55*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.39	.39	.39	.42	1.59
2016	.42	.42	.42	.45	1.71
2017	.45	.45	.45	.485	1.84
2018	.485	.485	.485	.525	1.98
2019	.525	.525	.525		

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 2018: 66%, residential; 28%, commercial; 5%, industrial; and 1% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately 1.4% of common stock (12/18 Proxy). President and Chief Executive Officer: Michael E. Haefner. Inc.: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy appears to be en route to a decent fiscal 2019, which ends September 30th. Through the first nine months, the bottom line increased 7.5%, to $3.88 a share, versus $3.61 generated the previous year. One driver was the natural gas distribution division, which received a boost from higher rates, mainly in the Mid-Tex and Mississippi segments, plus growth of the customer base (primarily within the Mid-Tex unit). Also, results of the pipeline & storage segment were supported partly by increased rates from the Gas Reliability Infrastructure Program filings approved during fiscal 2018 and 2019. Total operating expenses rose 5.3% for the period, although that's to be expected as the company expands. In spite of the unspectacular start, we think share net will advance close to 8%, to $4.30, for the year as a whole. Regarding fiscal 2020, 6% or so growth (to $4.55 a share), seems plausible, if operating margins widen further.

Michael Haefner intends to step down as CEO on September 30th. His reason is to deal with a certain health problem. The anticipated successor, Kevin Akers, has held various key positions since joining the company almost 30 years ago, including executive vice president (his current post) and president of both the Kentucky/Mid-States and Mississippi units. So, we think Atmos would be in very capable hands.

Finances are rock-solid. At the conclusion of the first nine months, cash on hand stood at $46.2 million. Moreover, long-term debt was a reasonable 38.5% of total capital, and short-term commitments did not seem to be a major hurdle. Too, $1.3 billion of common stock and/or debt securities remained available for issuance under a shelf registration statement. Lastly, the company can access a $1.5 billion commercial paper program and three revolving credit facilities aggregating $1.5 billion. All told, we believe it's capable of meeting working capital, capital expenditures, and other cash needs for some time. Acquisitions are also possible.

For now, these top-quality shares have unspectacular total return potential. This reflects recent stock-price strength and a dividend yield that's less than average for a natural gas utility.

Frederick L. Harris, III *August 30, 2019*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '09, 12¢; '10, 5¢; '11, (1¢); '18, $1.43. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next egs. rpt. due early Nov.
(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	100
Price Growth Persistence	95
Earnings Predictability	100

CHESAPEAKE UTIL. NYSE-CPK

RECENT PRICE 94.31 | P/E RATIO 26.1 (Trailing: 25.8 Median: 17.0) | RELATIVE P/E RATIO 1.60 | DIV'D YLD 1.7% | VALUE LINE

TIMELINESS 3 Lowered 6/28/19

SAFETY 2 New 6/5/15

TECHNICAL 2 Lowered 8/16/19

BETA .65 (1.00 = Market)

High:	23.2	23.3	28.1	29.7	32.6	40.8	52.7	61.1	70.0	86.4	93.4	96.3
Low:	14.6	14.7	18.7	24.0	26.6	30.6	37.5	44.4	52.3	63.0	66.4	77.6

Target Price Range 2022 | 2023 | 2024

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 9/14
Options: Yes
Shaded area indicates recession

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	140	(+50%)	12%
Low	100	(+5%)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	1	0	0	0	0	0	0
Options	0	0	0	1	5	0	0	9	0
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	66	87	81
to Sell	87	84	92
Hld's(000)	10589	10581	10679

% TOT. RETURN 7/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.3	-2.7
3 yr.	53.8	27.9
5 yr.	137.2	41.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
19.11	20.70	26.02	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	**40.60**	**42.85**	Revenues per sh	**63.75**
2.42	2.26	2.35	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	**6.75**	**7.25**	"Cash Flow" per sh	**9.00**
1.17	1.09	1.18	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	**3.50**	**3.75**	Earnings per sh A	**5.00**
.73	.75	.76	.77	.78	.81	.83	.87	.91	.96	1.01	1.07	1.12	1.19	1.26	1.39	**1.55**	**1.68**	Div'ds Decl'd per sh B■	**2.15**
1.39	2.07	3.74	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	**10.45**	**10.75**	Cap'l Spending per sh	**11.80**
8.59	9.07	9.60	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	**35.55**	**37.00**	Book Value per sh	**49.00**
8.49	8.60	8.82	10.03	10.17	10.24	14.09	14.29	14.35	14.40	14.46	14.59	15.27	16.30	16.34	16.38	**17.00**	**17.50**	Common Shs Outst'g C	**20.00**
12.7	15.0	16.8	17.9	16.7	14.2	14.2	12.2	14.2	14.8	15.6	17.7	19.1	21.8	27.8	22.9	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**24.0**
.72	.79	.89	.97	.89	.85	.95	.78	.89	.94	.88	.93	.96	1.14	1.40	1.24			Relative P/E Ratio	**1.35**
4.9%	4.6%	3.8%	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%			Avg Ann'l Div'd Yield	**1.8%**

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
268.8	427.5	418.0	392.5	444.3	498.8	459.2	498.9	617.6	717.5	**690**	**750**	Revenues ($mill)	**1275**
15.9	26.1	27.6	28.9	32.8	36.1	40.2	44.7	43.8	56.6	**60.0**	**65.0**	Net Profit ($mill)	**100**
41.8%	39.7%	39.4%	40.1%	40.2%	39.9%	39.5%	38.8%	39.5%	27.1%	**25.5%**	**26.0%**	Income Tax Rate	**27.0%**
5.9%	6.1%	6.6%	7.4%	7.4%	7.2%	8.8%	9.0%	7.1%	7.9%	**8.7%**	**8.7%**	Net Profit Margin	**7.8%**
32.0%	28.4%	31.4%	28.4%	29.7%	34.5%	29.4%	23.5%	28.9%	37.9%	**35.0%**	**38.0%**	Long-Term Debt Ratio	**30.0%**
68.0%	71.6%	68.6%	71.6%	70.3%	65.5%	70.6%	76.5%	71.1%	62.1%	**65.0%**	**62.0%**	Common Equity Ratio	**70.0%**
308.6	315.9	351.1	358.5	396.4	458.8	507.5	583.0	683.7	834.5	**930**	**1045**	Total Capital ($mill)	**1400**
436.4	462.8	487.7	541.8	631.2	689.8	855.0	986.7	1126.0	1384.0	**1475**	**1640**	Net Plant ($mill)	**2000**
6.1%	9.1%	8.9%	8.8%	8.8%	8.5%	8.9%	8.6%	7.3%	7.8%	**7.5%**	**7.5%**	Return on Total Cap'l	**8.0%**
7.6%	11.5%	11.5%	11.2%	11.8%	12.0%	11.2%	10.0%	9.0%	10.9%	**10.0%**	**10.0%**	Return on Shr. Equity	**10.0%**
7.6%	11.5%	11.5%	11.2%	11.8%	12.0%	11.2%	10.0%	9.0%	10.9%	**10.0%**	**10.0%**	Return on Com Equity	**10.0%**
3.8%	6.6%	6.6%	6.4%	7.1%	7.4%	6.8%	6.1%	4.9%	6.7%	**5.5%**	**5.5%**	Retained to Com Eq	**6.0%**
50%	42%	42%	43%	40%	38%	40%	39%	45%	39%	**44%**	**45%**	All Div'ds to Net Prof	**43%**

CAPITAL STRUCTURE as of 6/30/19
Total Debt $652.7 mill. Due in 5 Yrs $410.0 mill.
LT Debt $275.9 mill. LT Interest $15.0 mill.
(LT interest earned: 5.7x; total interest coverage: 5.7x) (34% of Cap'l)
Leases, Uncapitalized Annual rentals$2.4 mill.
Pfd Stock None
Pension Assets-12/18 $52.3 mill. Oblig. $70.1 mill.
Common Stock 16,403,776 shs. as of 7/31/19

MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2017	2018	6/30/19
Cash Assets	5.6	6.1	7.3
Other	173.0	185.4	116.9
Current Assets	178.6	191.5	124.2
Accts Payable	74.7	129.8	50.6
Debt Due	260.4	306.4	376.8
Other	77.9	92.0	85.0
Current Liab.	413.0	528.2	512.4
Fix. Chg. Cov.	749%	636%	640%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	4.0%	5.0%	9.5%
"Cash Flow"	9.0%	7.5%	8.0%
Earnings	9.0%	8.0%	9.0%
Dividends	5.0%	6.0%	9.0%
Book Value	10.0%	10.5%	9.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	146.3	102.3	108.3	142.0	498.9
2017	185.2	125.1	126.9	180.4	617.6
2018	239.4	136.7	140.3	201.1	717.5
2019	227.6	130.9	**135**	**196.5**	**690**
2020	**242**	**145**	**153**	**210**	**750**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1.33	.52	.29	.73	2.86
2017	1.17	.37	.42	.72	2.68
2018	1.64	.39	.34	1.08	3.45
2019	1.74	.50	**.45**	**.81**	**3.50**
2020	**1.85**	**.55**	**.51**	**.84**	**3.75**

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.27	.27	.288	.288	1.12
2016	.288	.288	.305	.305	1.19
2017	.305	.305	.325	.325	1.26
2018	.325	.325	.37	.37	1.39
2019	.37	.37	.405		

BUSINESS: Chesapeake Utilities Corporation consists of two units: Regulated Energy and Unregulated Energy. The Regulated Energy segment (45% of 2018 revenues) 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 (55% of 2018 revenues) wholesales and distributes propane; markets natural gas; and provides other unregulated energy services, including midstream services in Ohio. Officers and directors own 4.2% of common stock; T. Rowe Price, 13.7%; BlackRock, 9.2% (4/19 Proxy). CEO: Jeffry M. Householder. Inc.: Delaware. Address: 909 Silver Lake Boulevard, Dover, DE 19904. Tel.: (302) 734-6799. Internet: www.chpk.com.

Chesapeake Utilities Corp. performed nicely, from an earnings standpoint, during the first half of 2019. Indeed, share net of $2.24 was around 10% higher than the prior-year total of $2.03. This was mainly because of the Regulated Energy segment, driven by such factors as the Eastern Shore and Peninsula Pipeline service expansions and organic growth within the natural gas distribution business. Another positive was a diminished effective income tax rate. But the Unregulated Energy division was held back, to a certain extent, by lower results at the PESCO unit. Chesapeake's interest charges climbed substantially during the period, too.

We anticipate an underwhelming showing for the full year, however. Although the company seems headed for a good third quarter, the 2018 December-period figure of $1.08 a share will be quite difficult to surpass. Thus, the bottom line may end up at around $3.50, not much higher than last year's $3.45-a-share tally. But regarding 2020, profits in the neighborhood of $3.75 (a 7% advance) appear possible, aided partly by incremental benefits from prior acquisitions. Generally favorable weather conditions would be another plus.

Our 2022-2024 projections show that steady dividend increases will occur. Furthermore, the equity's payout ratio over that span ought to be roughly 45%, which should not place a major financial burden on Chesapeake. It's important to mention, though, that the current dividend yield of 1.7% is nothing to write home about when measured against those of other stocks in *Value Line's* Natural Gas Utility Industry.

These shares are hovering not very far from their all-time high reached earlier this year. We believe this can be traced, to a large degree, to the company's solid earnings thus far in 2019. Note, also, the 2 (Above Average) Safety rank, lower-than-market Beta coefficient, and relatively high Price Stability score.

Nevertheless, the price movement has resulted in subpar long-term capital appreciation potential. Furthermore, CPK stock is only an Average (3) selection for Timeliness.

Frederick L. Harris, III *August 30, 2019*

(A) Diluted shrs. Excludes nonrecurring items: '08, d7¢; '15, 6¢; '17, 87¢. Excludes discontinued operations: '03, d9¢; '04, d1¢. Next earnings report due early Nov.

(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	75
Price Growth Persistence	90
Earnings Predictability	90

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 44.81 | P/E RATIO 22.1 (Trailing: 33.2; Median: 16.0) | RELATIVE P/E RATIO 1.36 | DIV'D YLD 2.6% | VALUE LINE

High:	20.6	21.2	22.0	25.2	25.1	23.8	32.1	34.1	38.9	45.4	51.8	51.2	
Low:	12.3	15.0	16.7	19.8	19.3	19.5	21.9	26.8	30.5	33.7	35.6	43.9	

TIMELINESS 3 Lowered 8/17/18

SAFETY 1 Raised 9/15/06

TECHNICAL 2 Lowered 8/23/19

BETA .70 (1.00 = Market)

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/08
2-for-1 split 3/15
Options: Yes
Shaded area indicates recession

Target Price Range 2022 | 2023 | 2024

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(Nil)	3%
Low	40	(-10%)	Nil

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	3	5	7	4	0	1	1	1	1
to Sell	0	1	0	1	0	5	0	1	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	121	130	125
to Sell	111	111	117
Hld's(000)	58525	59156	59010

Percent shares traded 30 20 10

% TOT. RETURN 7/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.4	-2.7
3 yr.	44.7	27.9
5 yr.	124.6	41.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
31.14	30.44	38.10	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	*30.70*	*32.85*	Revenues per sh A	*35.60*
1.19	1.25	1.31	1.37	1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.74	*2.95*	*3.25*	"Cash Flow" per sh	*3.70*
.79	.85	.88	.93	.78	1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.74	*1.90*	*2.15*	Earnings per sh B	*2.50*
.41	.43	.45	.48	.51	.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	*1.17*	*1.21*	Div'ds Decl'd per sh C■	*1.33*
.57	.72	.64	.64	.73	.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	*2.20*	*2.25*	Cap'l Spending per sh	*2.30*
5.13	5.62	5.30	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	*17.05*	*18.30*	Book Value per sh D	*21.85*
81.70	83.22	82.64	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	*88.00*	*88.25*	Common Shs Outst'g E	*89.00*
14.0	15.3	16.8	16.1	21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
.80	.81	.89	.87	1.15	.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.85			Relative P/E Ratio	*.95*
3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.7%			Avg Ann'l Div'd Yield	*2.5%*

CAPITAL STRUCTURE as of 6/30/19
Total Debt $1435.7 mill. **Due in 5 Yrs** $370.4 mill.
LT Debt $1211.8 mill. **LT Interest** $46.3 mill.
Incl. $35.9 mill. capitalized leases.
(LT interest earned: 5.0x; total interest coverage: 5.0x)
Pension Assets-9/18 $357.4 mill. **Oblig.** $495.4 mill.
Pfd Stock None

Common Stock 89,980,410 shs. **as of 8/2/19**
MARKET CAP: $4.0 billion (Mid Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
2592.5	2639.3	3009.2	2248.9	3198.1	3738.1	2734.0	1880.9	2268.6	2915.1	*2700*	*2900*	Revenues ($mill) A	*3170*
101.0	101.8	106.5	112.4	113.7	176.9	153.7	138.1	149.4	240.5	*170*	*190*	Net Profit ($mill)	*220*
27.1%	41.4%	30.2%	7.1%	25.4%	30.2%	26.3%	15.5%	17.2%	NMF	*15.0%*	*15.0%*	Income Tax Rate	*15.0%*
3.9%	3.9%	3.5%	5.0%	3.6%	4.7%	5.6%	7.3%	6.6%	8.3%	*6.2%*	*6.6%*	Net Profit Margin	*7.0%*
39.8%	37.2%	35.5%	39.2%	36.6%	38.2%	43.2%	47.7%	44.6%	45.4%	*44.5%*	*43.0%*	Long-Term Debt Ratio	*40.0%*
60.2%	62.8%	64.5%	60.8%	63.4%	61.8%	56.8%	52.3%	55.4%	54.6%	*55.5%*	*57.0%*	Common Equity Ratio	*60.0%*
1144.8	1154.4	1203.1	1339.0	1400.3	1564.4	1950.6	2230.1	2233.7	2599.6	*2700*	*2835*	Total Capital ($mill)	*3240*
1064.4	1135.7	1295.9	1484.9	1643.1	1884.1	2128.3	2407.7	2609.7	2651.1	*2705*	*2760*	Net Plant ($mill)	*2925*
9.7%	9.7%	9.7%	9.2%	9.0%	12.1%	8.6%	6.9%	7.7%	10.2%	*7.5%*	*8.0%*	Return on Total Cap'l	*8.0%*
14.6%	14.0%	13.7%	13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	17.1%	*11.0%*	*12.0%*	Return on Shr. Equity	*11.5%*
14.6%	14.0%	13.7%	13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	17.1%	*11.0%*	*12.0%*	Return on Com Equity	*11.5%*
7.2%	6.7%	6.2%	6.2%	5.2%	11.0%	7.0%	4.8%	5.0%	10.3%	*4.5%*	*5.0%*	Retained to Com Eq	*5.0%*
50%	52%	55%	55%	59%	40%	50%	60%	59%	40%	*61%*	*56%*	All Div'ds to Net Prof	*53%*

CURRENT POSITION ($MILL.)	2017	2018	6/30/19
Cash Assets	2.2	1.5	26.3
Other	577.2	768.6	483.6
Current Assets	579.4	770.1	509.9
Accts Payable	280.6	373.5	243.3
Debt Due	431.4	275.5	223.9
Other	90.9	101.9	114.8
Current Liab.	802.9	750.9	582.0
Fix. Chg. Cov.	543%	545%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-3.5%	-3.5%	4.5%
"Cash Flow"	7.0%	8.0%	4.0%
Earnings	7.0%	5.5%	3.5%
Dividends	7.5%	6.5%	4.0%
Book Value	7.0%	8.0%	6.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2016	444.3	574.2	393.2	469.2	1880.9
2017	541.1	733.5	457.5	536.5	2268.6
2018	705.3	1019.0	543.4	647.3	2915.1
2019	811.8	866.3	434.9	*587.0*	*2700*
2020	*860*	*910*	*485*	*645*	*2900*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2016	.58	.91	.13	d.02	1.61
2017	.47	1.21	.20	d.14	1.73
2018	1.56	1.62	d.09	d.33	2.74
2019	.61	1.27	d.20	*.22*	*1.90*
2020	*.68*	*1.33*	*d.14*	*.28*	*2.15*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.23	.23	.23	.24	.93
2016	.24	.24	.24	.255	.98
2017	.255	.255	.255	.273	1.04
2018	.273	.273	.273	.2925	1.11
2019	.2925	.2925	.2925		

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 538,700 cust. at 9/30/18. Fiscal 2018 volume: 266 bill. cu. ft. (17% interruptible, 17% res., 9% commercial & elec. utility, 40% capacity release programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2018 dep. rate: 2.7%. Has 1,068 empls. Off./dir. own 1.3% of common; BlackRock, 13.2%; Vanguard, 9.7% (12/18 Proxy). Chairman, CEO & President: Laurence M. Downes. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

Since our May review, shares of New Jersey Resources have started to decline. In fact, over that time frame, the equity's price has receded about 8.5%. In comparison, the S&P 500 Index climbed roughly 2% over this same period.

Meanwhile, the company posted lower-than-expected June-quarter financial results. NJR's revenues fell 19.9% on a year-to-year basis, to $434.9 million. This reflected a 28.4% downturn in nonutility volumes partially offset by a 15.5% rise in utility revenues. This is evident in a 16.9% drop in system throughput, to 174.1 bcf during the quarter. On the margin front, operating costs declined 600 basis points, as a percentage of the top line, largely due to reduced nonutility gas purchases and decreased operation & maintenance expenses. Those line items fell 31% and 8.7% versus the year-ago period, respectively. On balance, the fiscal third-quarter bottom-line loss more than doubled to a deficit of $0.20 a share.

Thus, we have reduced our fiscal 2019 (ends September 30th) top- and bottom-line outlooks accordingly. At this point, NJR appears poised to register a roughly 7.5% downturn in revenues, to $2.7 billion, due to sharply lower volumes from the nonutility operations. Alternatively, the New Jersey Natural Gas (NJNG) segment continues to add new customer accounts. That regulated business has added 6,800 active meters in the first nine months of this year. Still, despite cost-cutting efforts, the diminished volumes and rising share count will probably equate to a more-than-30%-earnings-per-share downturn, to $1.90 for the year. This falls slightly below management's guidance range of $1.95-$2.05 a share.

We do look for things to turn around in fiscal 2020. Despite the uneven performance from the nonutility business, NJR continues to grow through its capital expansion program. Meanwhile, the NJNG segment is on pace to add 28,000-30,000 new customer accounts from fiscal 2019 through fiscal 2021. What's more, the company recently filed for a $128.2 million base-rate increase with the New Jersey Board of Public Utilities.

All told, these neutrally ranked shares appear richly valued at this juncture.

Bryan J. Fong *August 30, 2019*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due early Nov.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2018: $368.6 million, $4.20/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	75
Earnings Predictability	45

NISOURCE INC. NYSE-NI

RECENT PRICE **29.32** | P/E RATIO **22.0** (Trailing: 21.7 Median: 20.0) | RELATIVE P/E RATIO **1.35** | DIV'D YLD **2.7%** | **VALUE LINE**

TIMELINESS **3** Lowered 4/5/19
SAFETY **3** New 9/4/15
TECHNICAL **3** Lowered 8/16/19
BETA .55 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	19.8	15.8	18.0	24.0	26.2	33.5	44.9	49.2	26.9	27.8	28.1	30.3
Low:	10.4	7.8	14.1	17.7	22.3	24.8	32.1	16.0	19.0	21.7	22.4	24.7

Target Price Range 2022 | 2023 | 2024

2022-24 PROJECTIONS

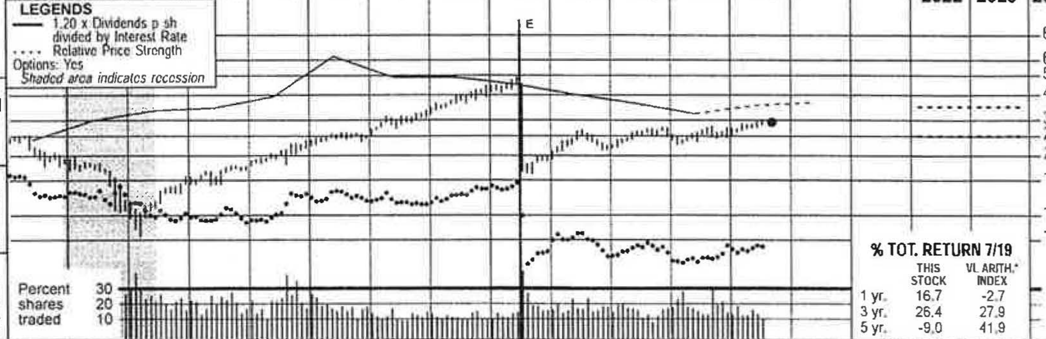
	Price	Gain	Ann'l Total Return
High	35	(+20%)	8%
Low	25	(-15%)	Nil

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	8	8	0	9	1
to Sell	0	1	0	0	0	0	0	0	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	237	218	236
to Sell	184	203	184
Hld's(000)	336574	347570	350564



% TOT. RETURN 7/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.7	-2.7
3 yr.	26.4	27.9
5 yr.	-9.0	41.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
23.78	24.63	28.97	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	**14.50**	**14.85**	Revenues per sh	**19.15**
3.47	3.47	3.14	3.18	3.20	3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.82	**3.05**	**3.20**	"Cash Flow" per sh	**3.75**
1.59	1.62	1.08	1.14	1.14	1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.01	.39	1.30	**1.30**	**1.40**	Earnings per sh A	**1.80**
1.10	.92	.92	.92	.92	.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	**.80**	**.86**	Div'd Decl'd per sh B ■	**1.20**
2.19	1.91	2.17	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	**4.60**	**4.60**	Cap'l Spending per sh	**5.15**
16.81	17.69	18.09	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	**16.15**	**17.55**	Book Value per sh C	**20.00**
262.63	270.63	272.62	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	**371.00**	**370.00**	Common Shs Outst'g D	**350.00**
12.2	13.0	21.4	19.2	18.8	12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	NMF	19.3	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
.70	.69	1.14	1.04	1.00	.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	NMF	1.04	*Value Line*		Relative P/E Ratio	**.90**
5.7%	4.4%	4.0%	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%	*estimates*		Avg Ann'l Div'd Yield	**4.2%**

CAPITAL STRUCTURE as of 6/30/19
Total Debt $9201.4 mill. **Due in 5 Yrs** $2100 mill.
LT Debt $7109.7 mill. **LT Interest** $370 mill.
(Interest cov. earned: 2.2x) (54% of Cap'l)

Leases, Uncapitalized Annual rentals $11.1 mill.
Pension Assets-12/18 $2.1 bill. **Oblig.** $2.0 bill.

Pfd Stock $880 mill. **Pfd Div'd** $28.5 mill.

Common Stock 373,347,237 shs.
as of 7/24/19
MARKET CAP: $10.9 billion (Large Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
6649.4	6422.0	6019.1	5061.2	5657.3	6470.6	4651.8	4492.5	4874.6	5114.5	**5380**	**5500**	Revenues ($mill)	**6700**
231.2	294.6	303.8	410.6	490.9	530.7	198.6	328.1	128.6	463.3	**475**	**515**	Net Profit ($mill)	**630**
41.8%	32.4%	35.0%	34.4%	34.8%	36.9%	41.6%	35.7%	71.0%	19.7%	**21.0%**	**21.0%**	Income Tax Rate	**21.0%**
--	--	--	--	--	--	--	--	2.9%	2.0%	**2.0%**	**2.0%**	AFUDC % to Net Profit	**2.0%**
55.1%	54.7%	55.6%	55.1%	56.3%	56.9%	60.7%	59.8%	63.5%	55.3%	**55.0%**	**54.0%**	Long-Term Debt Ratio	**53.0%**
44.9%	45.3%	44.4%	44.9%	43.7%	43.1%	39.3%	40.2%	36.5%	37.9%	**45.0%**	**46.0%**	Common Equity Ratio	**47.0%**
10819	10859	11264	12373	13480	14331	9792.0	10129	11832	12856	**13300**	**14000**	Total Capital ($mill)	**15000**
10592	11097	11800	12916	14365	16017	12112	13068	14360	15543	**16000**	**16500**	Net Plant ($mill)	**17000**
4.0%	4.5%	4.4%	5.0%	5.2%	5.3%	4.0%	5.0%	2.6%	5.0%	**5.0%**	**5.0%**	Return on Total Cap'l	**5.5%**
4.8%	6.0%	6.1%	7.4%	8.3%	8.6%	5.2%	8.1%	3.0%	8.1%	**8.0%**	**8.0%**	Return on Shr. Equity	**9.0%**
4.8%	6.0%	6.1%	7.4%	8.3%	8.6%	5.2%	8.1%	3.0%	9.3%	**8.0%**	**8.0%**	Return on Com Equity	**9.0%**
NMF	.8%	.9%	2.5%	3.1%	3.4%	NMF	3.0%	NMF	3.7%	**3.0%**	**3.0%**	Retained to Com Eq	**3.0%**
110%	87%	85%	67%	62%	61%	NMF	63%	NMF	61%	**64%**	**62%**	All Div'ds to Net Prof	**67%**

CURRENT POSITION ($MILL.)	2017	2018	6/30/19
Cash Assets	29.0	112.8	23.7
Other	1734.3	1942.6	1554.3
Current Assets	1763.3	2055.4	1578.0
Accts Payable	625.6	883.8	552.2
Debt Due	1490.0	2027.2	2091.7
Other	1062.8	1125.8	1169.8
Current Liab.	3178.4	4036.8	3813.7
Fix. Chg. Cov.	259%	246%	255%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-7.0%	-5.5%	5.5%
"Cash Flow"	-2.5%	-4.5%	6.5%
Earnings	-3.0%	-7.5%	12.5%
Dividends	-2.5%	-5.5%	9.0%
Book Value	-3.5%	-6.5%	7.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1436.6	897.6	861.3	1297.0	4492.5
2017	1598.6	990.7	917.0	1368.3	4874.6
2018	1750.8	1007.0	895.0	1461.7	5114.5
2019	1869.8	1010.4	**1019.8**	**1480**	**5380**
2020	**1900**	**1100**	**1000**	**1500**	**5500**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.58	.09	.07	.27	1.01
2017	.65	d.14	.04	d.16	.39
2018	.77	.07	.10	.38	1.30
2019	.82	.05	**.05**	**.38**	**1.30**
2020	**.85**	**.10**	**.10**	**.35**	**1.40**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.26	.26	.155	.155	.83
2016	.155	.155	.165	.165	.64
2017	.175	.175	.175	.175	.70
2018	.195	.195	.195	.195	.78
2019	.200	.200	.200		

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: 472,000 electric in Indiana, 3.5 million gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, Massachusetts through its Columbia subsidiaries. Revenue breakdown, 2018: electrical, 33%; gas, 67%; other, less than 1%. Generating sources, 2018: coal, 69.4%; purchased & other, 30.6%. 2018 reported depreciation rates: 2.9% electric, 2.2% gas. Has 8,087 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Joseph Hamrock. Incorporated: Indiana. Address: 801 East 86th Ave., Merrillville, Indiana 46410. Tel.: 877-647-5990. Internet: www.nisource.com.

NiSource registered weaker-than-expected second-quarter results. The top line was mostly flat, coming in at $1.01 billion. Meanwhile, the bottom line slipped to $0.05 per share, versus $0.07 a share in the year-ago period. Both its Gas Distribution and Electric operations experienced year-over-year declines of 3.8% and 6.8%, respectively, due to lower residential and commercial revenues. Higher operating expenses owing to increased spending in the gas segment, along with elevated interest costs, weighed on share net.

The Columbia Gas subsidiary recently settled Massachusetts gas explosion claims for $143 million. Approximately $1 billion (including the aforementioned settlement) were designated to conduct restoration work and provide temporary housing to the affected residents.

Share earnings may remain flat this year, but advance at a single-digit pace for 2020. NiSource is focused on gas system safety upgrades, especially after the Great Lawrence incident. Moreover, the implementation of its Safety Management System (SMS) seems to be proceeding smoothly. SMS improves operational risk management. Furthermore, new base-rates were settled in Virginia, increasing annual revenues by $9.5 million. Meanwhile, the company has two base-rate cases pending, which are expected to be approved by the fourth quarter (rates will go into effect early next year). Once the Maryland base rate is approved, it will likely result in incremental revenues of $2.5 million. Approval of these base rate cases should keep the company on track with its infrastructure enhancement activities. There will be near-term costs associated with the aforementioned initiatives. Therefore, we estimate share earnings for this year and next to come in at $1.30 and $1.40, respectively. For 2022-2024, we project share net of $1.80, as benefits from the ongoing upgrades increasingly contribute to the bottom line.

Shares of NiSource do not stand out for Timeliness. At the recent quotation, this issue has limited long-term total return potential. We remain wary of its above-average debt levels, which are needed to support its rising capital expenditures.

Emma Jalees *August 30, 2019*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, (4¢); gains (losses) on disc. ops.: '05, 10¢; '06, (11¢); '07, 3¢; '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due late October.
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 '18: $1911.4 million, $5.13/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	25
Earnings Predictability	35

N.W. NATURAL NYSE-NWN

RECENT PRICE 71.40 | P/E RATIO 29.1 (Trailing: 29.1 Median: 21.0) | RELATIVE P/E RATIO 1.79 | DIV'D YLD 2.7% | VALUE LINE

High:	55.2	46.5	50.9	49.0	50.8	46.6	52.6	52.3	66.2	69.5	71.8	73.5		
Low:	37.7	37.7	41.1	39.6	41.0	40.0	40.1	42.0	48.9	56.5	51.5	57.2		

TIMELINESS 3 Raised 11/9/18

SAFETY 1 Raised 3/18/05

TECHNICAL 3 Lowered 7/26/19

BETA .60 (1.00 = Market)

2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+20%)	7%
Low	70	(Nil)	2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	13	3	0	0	0
to Sell	0	0	1	0	0	4	1	0	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	78	98	112
to Sell	95	95	78
Hld's(000)	19034	19492	19999

Target Price Range

2022	2023	2024

% TOT. RETURN 7/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.8	-2.7
3 yr.	20.4	27.9
5 yr.	94.9	41.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	**27.20**	**28.05**	Revenues per sh	**28.45**
3.85	3.92	4.34	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	**5.10**	**5.45**	"Cash Flow" per sh	**6.35**
1.76	1.86	2.11	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	**2.40**	**2.60**	Earnings per sh A	**3.50**
1.27	1.30	1.32	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	**1.93**	**1.97**	Div'ds Decl'd per sh B■	**2.20**
4.90	5.52	3.48	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	**6.55**	**6.65**	Cap'l Spending per sh	**6.25**
19.52	20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	**26.55**	**26.85**	Book Value per sh D	**29.40**
25.94	27.55	27.58	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	**30.50**	**31.00**	Common Shs Outst'g C	**32.00**
15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	26.9	26.6	*Bold figures are*		Avg Ann'l P/E Ratio	**22.0**
.90	.88	.91	.86	.89	1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	1.41	1.44	*Value Line*		Relative P/E Ratio	**1.20**
4.6%	4.2%	3.7%	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%	*estimates*		Avg Ann'l Div'd Yield	**2.9%**
						1012.7	812.1	848.8	730.6	758.5	754.0	723.8	676.0	762.2	706.1	**830**	**870**	Revenues ($mill)	**910**
						75.1	72.7	63.9	59.9	60.5	58.7	53.7	58.9	d55.6	67.3	**85.0**	**85.0**	Net Profit ($mill)	**90.0**
						38.3%	40.5%	40.4%	42.4%	40.8%	41.5%	40.0%	40.9%	40.9%	26.4%	**21.0%**	**21.0%**	Income Tax Rate	**21.0%**
						7.4%	8.9%	7.5%	8.2%	8.0%	7.8%	7.4%	8.7%	NMF	9.5%	**8.8%**	**9.3%**	Net Profit Margin	**12.3%**
						47.7%	46.1%	47.3%	48.5%	47.6%	44.8%	42.5%	44.4%	47.9%	48.1%	**47.0%**	**47.0%**	Long-Term Debt Ratio	**46.5%**
						52.3%	53.9%	52.7%	51.5%	52.4%	55.2%	57.5%	55.6%	52.1%	51.9%	**53.0%**	**53.0%**	Common Equity Ratio	**53.5%**
						1261.8	1284.8	1356.2	1424.7	1433.6	1389.0	1357.7	1529.8	1426.0	1468.9	**1530**	**1615**	Total Capital ($mill)	**1750**
						1670.1	1854.2	1893.9	1973.6	2062.9	2121.6	2182.7	2260.9	2255.0	2421.4	**2510**	**2640**	Net Plant ($mill)	**2745**
						7.3%	7.0%	6.2%	5.7%	5.8%	5.8%	5.5%	5.1%	NMF	5.8%	**6.0%**	**6.0%**	Return on Total Cap'l	**7.5%**
						11.4%	10.5%	8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	**9.0%**	**9.0%**	Return on Shr. Equity	**12.0%**
						11.4%	10.5%	8.9%	8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	**9.0%**	**9.0%**	Return on Com Equity	**12.0%**
						5.0%	4.0%	2.4%	1.6%	1.5%	1.1%	.6%	.9%	NMF	2.1%	**2.0%**	**2.0%**	Retained to Com Eq	**4.5%**
						56%	61%	73%	80%	81%	85%	92%	87%	NMF	76%	**80%**	**76%**	All Div'ds to Net Prof	**63%**

CAPITAL STRUCTURE as of 6/30/19
Total Debt $930.6 mill. **Due in 5 Yrs** $360.0 mill.
LT Debt $806.1 mill. **LT Interest** $40.0 mill.

(Total interest coverage: 3.7x)

Pension Assets-12/18 $257.8 mill. **Oblig.** $455.6 mill.

Pfd Stock None

Common Stock 30,442,700 shares as of 7/26/19

MARKET CAP $2.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2017	2018	6/30/19
Cash Assets	3.5	12.6	60.9
Other	266.4	283.3	178.2
Current Assets	269.9	295.9	239.1
Accts Payable	112.3	115.9	76.4
Debt Due	150.9	247.6	124.5
Other	118.7	145.6	106.1
Current Liab.	381.9	509.1	307.0
Fix. Chg. Cov.	362%	357%	369%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-4.5%	-3.0%	2.5%
"Cash Flow"	-3.0%	-5.5%	9.0%
Earnings	-10.5%	-18.0%	27.0%
Dividends	2.5%	1.0%	2.5%
Book Value	2.0%	--	1.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	255.6	99.2	87.7	233.5	676.0
2017	297.3	136.3	88.2	240.4	762.2
2018	264.7	124.6	91.2	226.7	706.1
2019	285.3	123.4	**125**	**296.3**	**830**
2020	**300**	**140**	**130**	**300**	**870**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1.33	.07	d.29	1.01	2.12
2017	1.40	.10	d.30	d3.14	d1.94
2018	1.46	d.01	d.39	1.27	2.33
2019	1.50	.07	**d.45**	**1.28**	**2.40**
2020	**1.55**	**.10**	**d.35**	**1.30**	**2.60**

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.465	.465	.465	.4675	1.86
2016	.4675	.4675	.4675	.470	1.87
2017	.470	.470	.470	.4725	1.88
2018	.4725	.4725	.4725	.475	1.89
2019	.475	.475	.475		

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1000 communities, 750,000 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 15.0% of shares; officers and directors, 1.1% (4/19 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Holdings showed some improvement in its second-quarter results. Earnings per share rose to $0.07, helped by lower environmental expenses and higher allowable base rates in Oregon. The company added around 12,400 new customers in the past year, which also helped boost usage, and the Mist storage facility came into service and added to performance. Moreover, losses related to the company's stake in Gill Ranch were recorded as discontinued operations, owing to its pending sale. The second half of 2019 will likely be a bit weak, as the company returns some of the tax reform benefits to customers. Too, a rate case outcome will reduce interstate storage income. Meantime, both common stock and long-term debt were issued, driving interest expense higher and diluting share net. Still, a decent outcome on its Washington rate case, which covers around 11% of all customers, will probably offset this in the coming months. Overall, we think earnings will reach $2.40 per share this year.

The move into water utilities has helped operations considerably. The step into the space has helped diversify its business lines, while reducing seasonality a bit. Additionally, Northwest Natural recently acquired Falls Water Company, a municipal wastewater utility in Idaho Falls. This purchase will make up a smaller portion of the business, but allow for further growth in the years ahead. All told, we think earnings will reach $2.60 per share in 2020.

The Mist storage facility ought to help earnings expand in the coming years. This area was placed into service in May and will provide no-notice natural gas to Portland General Electric. Too, it will boost net income growth, especially when electricity demand is at its highest during weather extremes.

Dividend growth is steady. Though the yield is lower than at other utilities, the payout is safe and may start to expand at an improved rate in the coming years, aided by profits from the Mist facility.

Northwest Natural stock is neutrally ranked for Timeliness. Too, it is trading within our 3- to 5-year Target Price Range. Most accounts would be best served waiting for a dip in price.

John E. Seibert III *August 30, 2019*

(A) Diluted earnings per share. Excludes nonrecurring items: '06, ($0.06); '08, ($0.03); '09, 6c; May not sum due to rounding. Next earnings report due in early November.

(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.

(D) Includes intangibles. In 2018: $371.8 million, $12.87/share.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	5

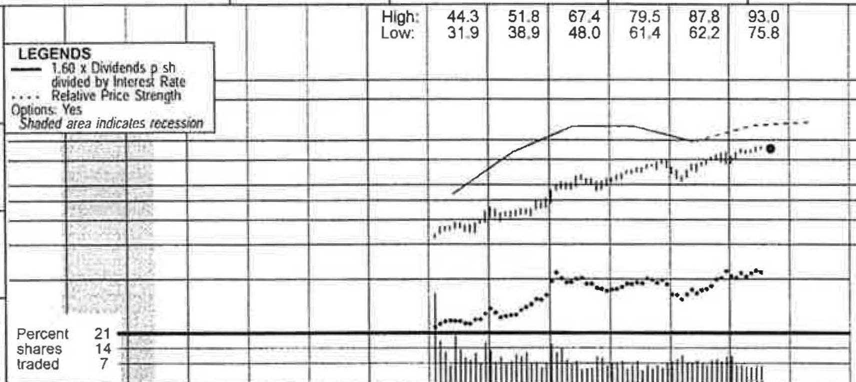
ONE GAS, INC. NYSE-OGS

RECENT PRICE 90.60 | P/E RATIO 25.8 (Trailing: 26.9 Median: NMF) | RELATIVE P/E RATIO 1.58 | DIV'D YLD 2.3% | VALUE LINE

TIMELINESS 3 Lowered 8/9/19
SAFETY 2 New 6/2/17
TECHNICAL 2 Raised 6/14/19
BETA .65 (1.00 = Market)

High:	44.3	51.8	67.4	79.5	87.8	93.0
Low:	31.9	38.9	48.0	61.4	62.2	75.8

Target Price Range 2022 | 2023 | 2024



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	135	(+50%)	12%
Low	100	(+10%)	5%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	4	0	0	5	0
to Sell	0	0	0	0	0	1	0	0	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	129	137	152
to Sell	134	138	124
Hld's(000)	39573	39774	40068

% TOT. RETURN 7/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.1	-2.7
3 yr.	50.8	27.9
5 yr.	185.0	41.9

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.

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
--	--	--	--	--	34.92	29.62	27.30	29.43	31.08	**31.40**	**32.70**	Revenues per sh	**40.00**
--	--	--	--	--	4.52	4.82	5.43	5.96	6.32	**6.90**	**7.25**	"Cash Flow" per sh	**9.00**
--	--	--	--	--	2.07	2.24	2.65	3.02	3.25	**3.45**	**3.65**	Earnings per sh A	**4.75**
--	--	--	--	--	.84	1.20	1.40	1.68	1.84	**2.00**	**2.16**	Div'ds Decl'd per sh B■	**2.65**
--	--	--	--	--	5.70	5.63	5.91	6.81	7.50	**8.50**	**8.70**	Cap'l Spending per sh	**8.90**
--	--	--	--	--	34.45	35.24	36.12	37.47	38.86	**41.05**	**42.75**	Book Value per sh	**47.90**
--	--	--	--	--	52.08	52.26	52.28	52.31	52.57	**53.00**	**53.50**	Common Shs Outst'g C	**55.00**
--	--	--	--	--	17.8	19.8	22.7	23.5	23.1	*Bold figures are*		Avg Ann'l P/E Ratio	**25.0**
--	--	--	--	--	.94	1.00	1.19	1.18	1.25	*Value Line*		Relative P/E Ratio	**1.40**
--	--	--	--	--	2.3%	2.7%	2.3%	2.4%	2.5%	*estimates*		Avg Ann'l Div'd Yield	**2.3%**
--	--	--	--	--	1818.9	1547.7	1427.2	1539.6	1633.7	**1665**	**1750**	Revenues ($mill)	**2200**
--	--	--	--	--	109.8	119.0	140.1	159.9	172.2	**185**	**195**	Net Profit ($mill)	**260**
--	--	--	--	--	38.4%	38.0%	37.8%	36.4%	23.7%	**21.5%**	**22.0%**	Income Tax Rate	**23.5%**
--	--	--	--	--	6.0%	7.7%	9.8%	10.4%	10.5%	**11.1%**	**11.1%**	Net Profit Margin	**11.8%**
--	--	--	--	--	40.1%	39.5%	38.7%	37.8%	38.6%	**38.0%**	**38.0%**	Long-Term Debt Ratio	**38.0%**
--	--	--	--	--	59.9%	60.5%	61.3%	62.2%	61.4%	**62.0%**	**62.0%**	Common Equity Ratio	**62.0%**
--	--	--	--	--	2995.3	3042.9	3080.7	3153.5	3328.1	**3510**	**3690**	Total Capital ($mill)	**4250**
--	--	--	--	--	3293.7	3511.9	3731.6	4007.6	4283.7	**4500**	**4700**	Net Plant ($mill)	**5400**
--	--	--	--	--	4.4%	4.7%	5.2%	5.8%	6.0%	**6.5%**	**6.5%**	Return on Total Cap'l	**7.5%**
--	--	--	--	--	6.1%	6.5%	7.4%	8.2%	8.4%	**8.5%**	**8.5%**	Return on Shr. Equity	**10.0%**
--	--	--	--	--	6.1%	6.5%	7.4%	8.2%	8.4%	**8.5%**	**8.5%**	Return on Com Equity	**10.0%**
--	--	--	--	--	3.7%	3.1%	3.5%	3.7%	3.7%	**3.5%**	**3.5%**	Retained to Com Eq	**4.5%**
--	--	--	--	--	40%	53%	52%	55%	56%	**57%**	**59%**	All Div'ds to Net Prof	**56%**

CAPITAL STRUCTURE as of 6/30/19
Total Debt $1578.8 mill. **Due in 5 Yrs** $300.0 mill.
LT Debt $1285.8 mill. **LT Interest** $75.0 mill.
(LT interest earned: 5.4x; total interest coverage: 5.4x)
Leases, Uncapitalized Annual rentals $6.3 mill.
Pfd Stock None
Pension Assets-12/18 $814.1 mill. **Oblig.** $950.5 mill.
Common Stock 52,734,526 shs. as of 7/22/19
MARKET CAP: $4.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2017	2018	6/30/19
Cash Assets	14.4	21.3	11.1
Other	574.6	522.0	365.7
Current Assets	589.0	543.3	376.8
Accts Payable	143.7	174.5	67.6
Debt Due	357.2	299.5	293.0
Other	172.4	224.9	217.8
Current Liab.	673.3	698.9	578.4
Fix. Chg. Cov.	774%	677%	700%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	--	--	5.5%
"Cash Flow"	--	--	7.5%
Earnings	--	--	8.0%
Dividends	--	--	8.5%
Book Value	--	--	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	508.4	245.9	232.2	440.7	1427.2
2017	550.4	279.7	247.1	462.4	1539.6
2018	638.5	292.5	238.3	464.4	1633.7
2019	661.0	290.6	*245*	*468.4*	*1665*
2020	*700*	*320*	*255*	*475*	*1750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1.22	.38	.25	.80	2.65
2017	1.34	.39	.36	.93	3.02
2018	1.72	.39	.31	.84	3.25
2019	1.76	.46	*.35*	*.88*	*3.45*
2020	*1.82*	*.51*	*.40*	*.92*	*3.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.30	.30	.30	.30	1.20
2016	.35	.35	.35	.35	1.40
2017	.42	.42	.42	.42	1.68
2018	.46	.46	.46	.46	1.84
2019	.50	.50	.50		

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to over two million customers. It has three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 180 Bcf of natural gas supply in 2018, compared to 137 Bcf in 2017. Total volumes delivered by customer (fiscal 2018): transportation, 56%; residential, 33%; commercial & industrial, 10%; wholesale & public authority, 1%. BlackRock owns approximately 11.9% of common stock; The Vanguard Group, 9.9%; T. Rowe Price Associates, 8.5%; officers and directors, less than 1% (4/19 Proxy). CEO: Pierce H. Norton II. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Telephone: 918-947-7000. Internet: www.onegas.com.

ONE Gas had a decent first half of 2019. In fact, earnings per share advanced 5.2%, to $2.22, relative to the previous year's tally of $2.11. That was made possible partially by new rates in Kansas and Texas. Another positive was a lower income tax rate. Increased volumes in Texas and customer growth in Oklahoma and Texas helped the company's results, as well. However, one detractor was a 28% jump in interest expense. Total operating expenses climbed 4.5% during the period, but this reflects necessary capital investments.

Right now, it seems that profits will grow around 6%, to $3.45 a share, for the entire year. That's compared to the 2018 figure of $3.25. Looking at next year, we expect ONE Gas' bottom line to rise at a similar percentage rate, to $3.65 a share, assuming additional expansion of operating margins.

***Value Line* is constructive about the company's prospects over the 2022-2024 period.** It is now the leading natural gas distributor (as measured by customer count) in both Oklahoma and Kansas, and holds the number-three position in Texas. What's more, these markets appear to have decent growth possibilities and are located in one of the most active drilling regions in the United States. Also, with solid finances, ONE Gas ought to be able to meet its working capital requirements, capital expenditures, and other commitments for quite a while.

There are risks to consider, nonetheless. Among them is the fact that businesses are concentrated in only three states, and it looks like leadership desires to keep things as they are. This lack of geographic diversification leaves the company somewhat more vulnerable to regional economic downturns and regulations. Furthermore, ONE Gas faces competition from other energy suppliers, including electric companies and propane dealers. Also, pipeline ruptures, leaks, and other unfortunate events can take a huge bite out of earnings if not sufficiently covered by insurance.

The stock's total return potential is decent versus other natural gas utilities we track. Meanwhile, the Timeliness rank resides at 3 (Average).

Frederick L. Harris, III *August 30, 2019*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Nov. Quarterly EPS for 2018 don't add up due to rounding.
(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	A
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	95

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE **31.50** | P/E RATIO **26.0** (Trailing: 29.2, Median: 18.0) | RELATIVE P/E RATIO **1.60** | DIV'D YLD **3.9%** | VALUE LINE

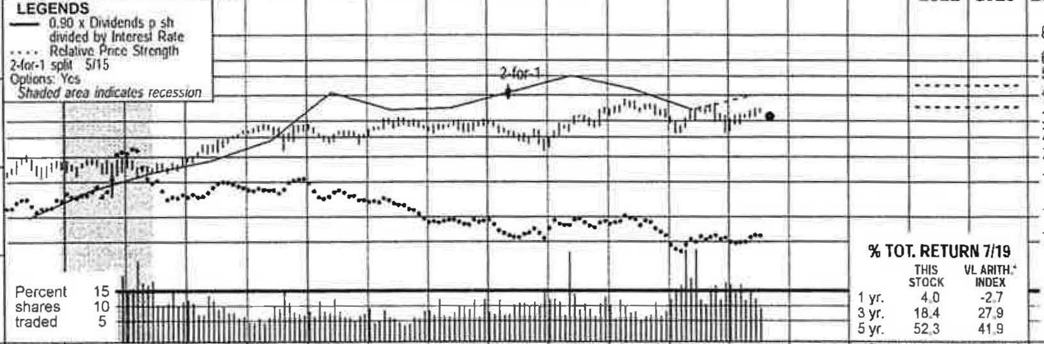
TIMELINESS	3	Lowered 7/20/18
SAFETY	2	Lowered 1/4/91
TECHNICAL	2	Lowered 8/30/19

BETA .80 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	20.3	20.4	27.1	29.0	29.0	31.1	30.6	30.4	34.8	38.4	36.7	34.5
Low:	12.6	16.0	18.6	21.4	22.9	25.3	25.9	21.2	22.1	30.8	26.0	26.6

Target Price Range 2022 | 2023 | 2024

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/15
Options: Yes
Shaded area indicates recession



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+45%)	12%
Low	35	(+10%)	6%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	1	2	0	0	0	0	0	0
Options	0	0	0	16	0	8	0	0	4
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	99	125	137
to Sell	124	104	86
Hld's(000)	71247	72623	76619

% TOT. RETURN 7/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	4.0	-2.7
3 yr.	18.4	27.9
5 yr.	52.3	41.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
13.17	14.75	15.89	15.86	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.52	13.04	15.63	19.20	17.55	17.95	Revenues per sh	21.00
1.12	1.22	1.25	1.75	1.60	1.74	1.86	2.10	2.23	2.34	2.48	2.67	2.42	2.67	2.79	2.91	2.15	2.70	"Cash Flow" per sh	3.75
.68	.79	.86	1.23	1.05	1.14	1.19	1.35	1.45	1.52	1.52	1.57	1.44	1.34	1.23	1.38	1.10	1.60	Earnings per sh A	2.40
.39	.41	.43	.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.06	1.10	1.13	1.20	1.25	Div'ds Decl'd per sh B ■	1.40
1.18	1.34	1.60	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	5.65	5.90	Cap'l Spending per sh	7.50
5.63	6.20	6.75	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	16.50	17.20	Book Value per sh C	20.00
52.92	55.52	57.96	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	94.00	96.00	Common Shs Outst'g D	100.00
13.3	14.1	16.6	11.9	17.2	15.9	15.0	16.8	18.4	16.9	18.9	18.0	17.9	21.7	27.9	22.6	Bold figures are		Avg Ann'l P/E Ratio	16.0
.76	.74	.88	.64	.91	.96	1.00	1.07	1.15	1.08	1.06	.95	.90	1.14	1.40	1.22	Value Line		Relative P/E Ratio	.90
4.3%	3.7%	3.0%	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%	estimates		Avg Ann'l Div'd Yield	3.6%

CAPITAL STRUCTURE as of 6/30/19
Total Debt $2957.5 mill. Due in 5 Yrs $1623 mill.
LT Debt $1798.6 mill. LT Interest $75.0 mill.

Leases, Uncapitalized Annual rentals $.8 mill.
Pension Assets-12/18 $287.2 mill. Oblig. $402.2 mill.

Pfd Stock None

Common Stock 92,390,349 shs. as of 8/1/19

MARKET CAP: $2.9 billion (Mid Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
845.4	925.1	828.6	706.3	731.4	887.0	959.6	1036.5	1243.1	1641.3	1650	1725	Revenues ($mill)	2100
71.3	81.0	87.0	93.3	97.1	104.0	99.0	102.8	98.1	116.2	100	150	Net Profit ($mill)	235
23.0%	15.2%	22.4%	10.8%	--	--	5.9%	42.0%	42.0%	21.0%	22.0%	21.0%	Income Tax Rate	21.0%
8.4%	8.8%	10.5%	13.2%	13.3%	11.7%	10.3%	9.9%	7.9%	7.1%	6.1%	8.7%	Net Profit Margin	11.2%
36.5%	37.4%	40.5%	45.0%	45.1%	48.0%	49.2%	38.5%	48.5%	62.4%	56.5%	57.0%	Long-Term Debt Ratio	56.5%
63.5%	62.6%	59.5%	55.0%	54.9%	52.0%	50.8%	61.5%	51.5%	37.6%	43.5%	43.0%	Common Equity Ratio	43.5%
856.4	910.1	1048.3	1337.6	1507.4	1791.9	2043.9	2097.2	2315.4	3373.9	3550	3850	Total Capital ($mill)	4600
1073.1	1193.3	1352.4	1578.0	1859.1	2134.1	2448.1	2623.8	2700.2	3653.5	4100	4600	Net Plant ($mill)	6000
9.0%	9.5%	8.9%	7.4%	6.8%	6.4%	5.4%	5.4%	5.1%	4.4%	4.0%	5.0%	Return on Total Cap'l	6.0%
13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	6.5%	9.0%	Return on Shr. Equity	12.0%
13.1%	14.2%	13.9%	12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	6.5%	9.0%	Return on Com Equity	12.0%
6.4%	7.1%	6.7%	5.8%	4.8%	4.3%	2.8%	1.6%	.9%	1.7%	NMF	2.0%	Retained to Com Eq	5.0%
51%	50%	52%	55%	59%	61%	71%	80%	89%	82%	NMF	80%	All Div'ds to Net Prof	60%

CURRENT POSITION ($MILL.)

	2017	2018	6/30/19
Cash Assets	7.8	30.0	12.2
Other	431.2	633.2	416.8
Current Assets	439.0	663.2	429.0
Accts Payable	284.9	410.5	288.9
Debt Due	410.2	1004.4	1158.9
Other	188.0	165.9	198.3
Current Liab.	883.1	1580.8	1646.1
Fix. Chg. Cov.	177%	112%	171%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	--	6.0%	4.5%
"Cash Flow"	5.0%	3.5%	5.0%
Earnings	1.5%	-2.5%	10.5%
Dividends	8.0%	6.0%	4.0%
Book Value	6.5%	6.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	333.0	154.4	219.1	330.0	1036.5
2017	425.8	244.4	227.1	345.8	1243.1
2018	521.9	227.3	302.5	589.6	1641.3
2019	637.3	266.9	275	470.8	1650
2020	650	275	300	500	1725

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	.75	.12	.05	.42	1.34
2017	.72	.06	d.05	.50	1.23
2018	1.19	.07	d.27	.39	1.38
2019	1.09	d.13	d.30	.44	1.10
2020	1.20	.05	d.15	.50	1.60

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	--	.251	.251	.515	1.02
2016	--	.264	.264	.536	1.06
2017	--	.273	.273	.553	1.10
2018	--	.280	.280	.567	1.13
2019	--	.287	.287		

BUSINESS: South Jersey Industries, Inc. is a holding company. Dist. natural gas to approx. 685,000 customers in New Jersey and Maryland. South Jersey Gas rev. mix '18: residential, 46%; commercial, 22%; cogen. and electric gen., 13%; industrial, 19%. Acq. Elizabethtown Gas and Elkton Gas, 7/18. Nonutil. operations include South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 1,100 employees. Off./dir. own less than 1% of common; BlackRock, 14.9%; The Vanguard Group, 10.9% (3/19 proxy). Pres. & CEO: Michael J. Renna. Chairman: Walter M. Higgins III. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have traded in a fairly narrow range in recent times. The company posted mixed results in the second quarter. The top line advanced roughly 17%, on a year-over-year basis. However, expenses also increased (excluding an impairment charge of $99.2 million in the year-ago period). All told, South Jersey posted a share deficit of $0.13 for the term. Results ought to remain mixed in the back half of the year. Overall, we anticipate a modest top-line advance along with a significant share-earnings pullback for full-year 2019.

Top-line growth ought to pick up in 2020, and we project a strong bottom-line rebound for the company in that year. Favorable results should continue thereafter. An ongoing transition ought to leave the company a more regulated entity. Utility South Jersey Gas should continue to benefit from customer growth, driven by conversions from alternative fuels by new customers. Infrastructure replacement programs allow this business to earn an authorized return on approved investments. Elizabethtown Gas (acquired along with Elkton Gas in July of 2018) is seeking a base-rate revenue increase of about $65 million to recognize infrastructure investments for its natural gas system. A final decision in the matter is expected by the end of the current year. Important infrastructure investments should modernize the company's system and allow it to meet strong demand for natural gas. We envision some improvement on the nonutility side, as well, though a measure of unevenness may well persist. Efforts by the company to divest noncore operations should pay off.

This stock is ranked to perform in line with the broader market averages for the coming six to 12 months. Looking further out, this equity offers decent risk-adjusted total return potential for the pull to early next decade. This should be supported by strong operating performance at the company and a healthy dividend yield. Moreover, South Jersey earns good marks for Safety, Financial Strength, and Price Stability. Volatility is subdued, as well. All told, conservative, income-seeking accounts may find something to like here.

Michael Napoli, CFA — *August 30, 2019*

(A) Based on economic egs. from 2007. GAAP EPS: '08, $1.29; '09, $0.97; '10, $1.11; '11, $1.49; '12, $1.49; '13, $1.28; '14, $1.46; '15, $1.52; '16, $1.56; '17, ($0.04). Excl. nonrecur. gain (loss): '08, $0.16; '09, ($0.22); '10, ($0.24); '11, $0.04; '12, ($0.03); '13, ($0.24); '14, ($0.11); '15, $0.08; '16, $0.22; '17, ($1.27); '18, ($1.17). Next egs. rpt. early November.
(B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2018: $663.0 mill., $7.75 per shr.
(D) In mill., adj. for split.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	20
Earnings Predictability	65

SOUTHWEST GAS NYSE-SWX

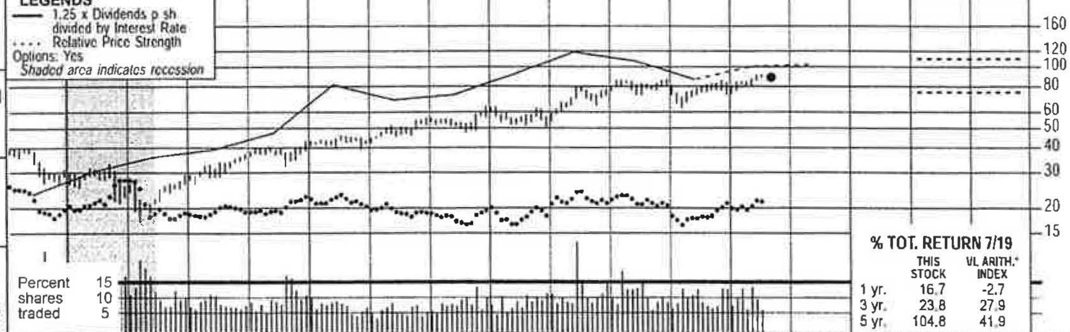
RECENT PRICE **88.90** | P/E RATIO **21.5** (Trailing: 23.5 / Median: 17.0) | RELATIVE P/E RATIO **1.32** | DIV'D YLD **2.5%** | **VALUE LINE**

TIMELINESS **2** Raised 8/23/19
SAFETY **3** Lowered 1/4/91
TECHNICAL **3** Lowered 8/30/19
BETA .70 (1.00 = Market)

High:	33.3	29.5	37.3	43.2	46.1	56.0	64.2	63.7	79.6	86.9	86.0	91.9	
Low:	21.1	17.1	26.3	32.1	39.0	42.0	47.2	50.5	53.5	72.3	62.5	73.3	

Target Price Range
2022 | 2023 | 2024

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+25%)	8%
Low	75	(-15%)	-1%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	1	0	0	1
Options	0	0	17	0	0	19	0	0	0
to Sell	0	0	0	0	0	2	0	2	1

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	122	140	150
to Sell	126	112	115
Hld's(000)	40794	44491	44254

Percent shares traded 15 10 5

% TOT. RETURN 7/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.7	-2.7
3 yr.	23.8	27.9
5 yr.	104.8	41.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
35.96	40.14	43.59	48.47	50.28	48.53	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	**56.35**	**58.95**	Revenues per sh	**68.95**
5.11	5.57	5.20	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	**9.35**	**10.10**	"Cash Flow" per sh	**13.55**
1.13	1.66	1.25	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	**4.00**	**4.40**	Earnings per sh A	**5.80**
.82	.82	.82	.82	.86	.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	**2.18**	**2.30**	Div'ds Decl'd per sh B■†	**2.60**
7.03	8.23	7.49	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	**16.35**	**16.95**	Cap'l Spending per sh	**20.70**
18.42	19.18	19.10	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	**45.45**	**48.20**	Book Value per sh	**58.60**
34.23	36.79	39.33	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	**55.00**	**56.00**	Common Shs Outst'g C	**58.00**
19.2	14.3	20.6	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	*Bold figures are*		Avg Ann'l P/E Ratio	**16.0**
1.09	.76	1.10	.86	.92	1.22	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	*Value Line*		Relative P/E Ratio	**.90**
3.8%	3.5%	3.2%	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%	*estimates*		Avg Ann'l Div'd Yield	**2.8%**

CAPITAL STRUCTURE as of 6/30/19
Total Debt $2409.8 mill. **Due in 5 Yrs** $869.1 mill.
LT Debt $2373.0 mill. **LT Interest** $100.0 mill.
(Total interest coverage: 3.6x) (50% of Cap'l)
Leases, Uncapitalized Annual rentals $11.0 mill.
Pension Assets-12/18 $838.0 mill.
Oblig. $1186.0 mill.

Pfd Stock None

Common Stock 54,324,289 shs.
as of 7/31/19

MARKET CAP: $4.8 billion (Mid Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
1893.8	1830.4	1887.2	1927.8	1950.8	2121.7	2463.6	2460.5	2548.8	2880.0	**3100**	**3300**	Revenues ($mill)	**4000**
87.5	103.9	112.3	133.3	145.3	141.1	138.3	152.0	173.8	182.3	**215**	**240**	Net Profit ($mill)	**335**
34.0%	34.7%	36.2%	36.2%	35.0%	35.7%	36.4%	33.9%	32.8%	25.3%	**21.0%**	**21.0%**	Income Tax Rate	**21.0%**
4.6%	5.7%	6.0%	6.9%	7.4%	6.7%	5.6%	6.2%	6.8%	6.3%	**6.9%**	**7.3%**	Net Profit Margin	**8.4%**
53.5%	49.1%	43.2%	49.2%	49.4%	52.4%	49.3%	48.2%	49.8%	48.3%	**49.5%**	**48.5%**	Long-Term Debt Ratio	**45.5%**
46.5%	50.9%	56.8%	50.8%	50.6%	47.6%	50.7%	51.8%	50.2%	51.7%	**50.5%**	**51.5%**	Common Equity Ratio	**54.5%**
2371.4	2291.7	2155.9	2576.9	2793.7	3123.9	3143.5	3213.5	3613.3	4359.3	**4950**	**5250**	Total Capital ($mill)	**6250**
3034.5	3072.4	3218.9	3343.8	3486.1	3658.4	3891.1	4132.0	4523.7	5093.2	**5450**	**5850**	Net Plant ($mill)	**7000**
5.4%	6.1%	6.4%	6.4%	6.3%	5.7%	5.5%	5.8%	5.8%	5.2%	**5.5%**	**5.5%**	Return on Total Cap'l	**6.5%**
7.9%	8.9%	9.2%	10.2%	10.3%	9.5%	8.7%	9.1%	9.6%	8.1%	**8.5%**	**9.0%**	Return on Shr. Equity	**10.0%**
7.9%	8.9%	9.2%	10.2%	10.3%	9.5%	8.7%	9.1%	9.6%	8.1%	**8.5%**	**9.0%**	Return on Com Equity	**10.0%**
4.1%	5.1%	5.3%	6.1%	6.1%	5.0%	4.0%	4.1%	4.5%	3.6%	**4.0%**	**4.0%**	Retained to Com Eq	**5.5%**
48%	43%	43%	40%	41%	47%	54%	55%	53%	55%	**56%**	**54%**	All Div'ds to Net Prof	**45%**

CURRENT POSITION ($MILL.)

	2017	2018	6/30/19
Cash Assets	43.6	85.4	38.4
Other	613.4	754.4	713.7
Current Assets	657.0	839.8	752.1
Accts Payable	228.3	249.0	196.9
Debt Due	239.8	185.1	36.8
Other	347.8	504.5	492.8
Current Liab.	815.9	938.6	726.5
Fix. Chg. Cov.	415%	370%	457%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	1.0%	5.0%	4.5%
"Cash Flow"	4.0%	3.0%	7.5%
Earnings	7.0%	4.5%	9.0%
Dividends	8.5%	10.5%	5.0%
Book Value	5.5%	6.0%	7.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	731.2	547.8	540.0	641.5	2460.5
2017	654.7	560.5	593.2	740.4	2548.8
2018	754.3	670.9	668.1	786.7	2880.0
2019	833.5	713.0	*720*	*833.5*	*3100*
2020	*860*	*775*	*780*	*885*	*3300*

Cal-endar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2016	1.58	.19	.05	1.36	3.18
2017	1.45	.37	.21	1.58	3.62
2018	1.63	.44	.25	1.36	3.68
2019	1.77	.41	*.26*	*1.56*	*4.00*
2020	*1.90*	*.50*	*.30*	*1.70*	*4.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.365	.405	.405	.405	1.58
2016	.405	.450	.450	.450	1.76
2017	.450	.495	.495	.495	1.94
2018	.495	.520	.520	.520	2.06
2019	.520	.545			

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas and Centuri Construction Group. Southwest Gas is a regulated gas distributor serving about 2.0 million customers in sections of Arizona, Nevada, and California. Centuri provides construction services. 2018 margin mix: residential and small commercial, 85%; large commercial and industrial, 3%; transportation, 12%. Total throughput: 2.2 billion therms. Has 8,632 employees. Off. & dir. own .8% of common stock; BlackRock Inc., 11.7%; The Vanguard Group, Inc., 10.1% (3/19 Proxy). Chairman: Michael J. Melarkey. President & CEO: John P. Hester. Inc.: CA. Addr.: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Shares of Southwest Gas have recently come off an all-time high. The company posted decent results for the second quarter. The top line increased moderately, year over year. Southwest's natural gas utility operation benefited from customer growth and rate relief in California and Nevada. Offsetting these gains were the effects of surcharges and the regulatory impacts of tax reform. Growth in the utility infrastructure services segment was the result of the addition of Linetec Services, LLC (acquired last year) and a greater volume of pipe replacement work under existing master service agreements and bid contracts. Operating expenses also increased. All told, net profit advanced about 2%, to $22.1 million. Still, earnings per share of $0.41 came in shy of the prior-year tally, owing to a larger share count.

We anticipate solid performance in the coming quarters. We project that revenues and share earnings will advance 8% and 9%, respectively, for full-year 2019. Growth should continue from 2020 onward. Southwest's utility operation is experiencing healthy economic growth throughout its service territories. Investment in infrastructure should pay off. The company is seeking regulatory approval to construct the infrastructure necessary to expand natural gas service into Spring Creek, Nevada. On the nonutility side, expanded service offerings for the company's infrastructure services customers ought to benefit results.

This stock is ranked to outperform the broader market averages for the coming six to 12 months. Looking further out, we anticipate moderate top-line growth and healthy share-net improvement for the company over the pull to early next decade. But this seems to be partly discounted by the recent quotation. Long-term total return potential appears to be limited, as the shares presently trade well within our Target Price Range. The dividend yield does not stand out for a utility, either. In the plus column, Southwest Gas earns good marks for Price Stability, Growth Persistence, and Earnings Predictability. Volatility is below average, as well. A pullback some time in the future may present conservative investors with a better entry point.

Michael Napoli, CFA *August 30, 2019*

(A) Diluted earnings. Excl. nonrec. gains (losses): '02, (10¢); '05, (11¢); '06, 7¢. Next egs. report due late October. (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	B++
Stock's Price Stability	85
Price Growth Persistence	80
Earnings Predictability	90

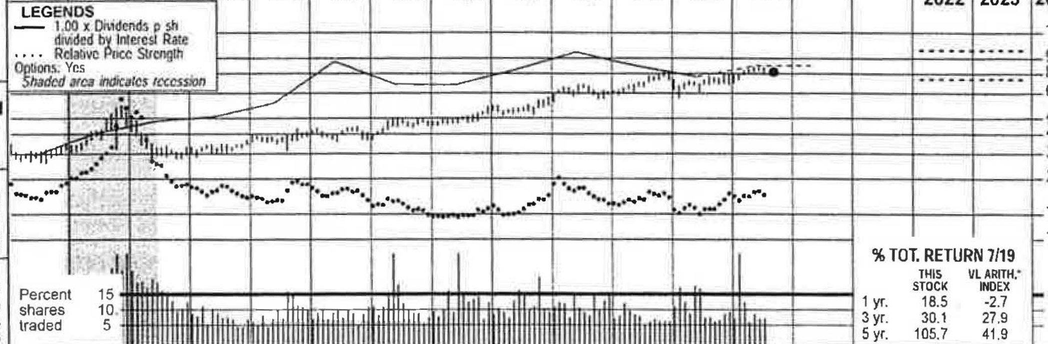
SPIRE INC. NYSE-SR

RECENT PRICE 81.66 | P/E RATIO 24.8 (Trailing: 21.7 Median: 17.0) | RELATIVE P/E RATIO 1.52 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 11/30/18
SAFETY 2 Raised 6/20/03
TECHNICAL 1 Raised 8/9/19
BETA .65 (1.00 = Market)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	55.8	48.3	37.8	42.8	44.0	48.5	55.2	61.0	71.2	82.9	81.1	87.1
Low:	31.9	29.3	30.8	32.9	36.5	37.4	44.0	49.1	57.1	62.3	60.1	71.7

Target Price Range 2022 | 2023 | 2024



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	105	(+30%)	9%
Low	75	(-10%)	1%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	5	5	0	8	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	119	118	140
to Sell	124	106	114
Hld's(000)	42187	41743	40023

Percent shares traded 15 10 5

% TOT. RETURN 7/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.5	-2.7
3 yr.	30.1	27.9
5 yr.	105.7	41.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
54.95	59.59	75.43	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	**38.80**	**40.40**	Revenues per sh A	**54.55**
3.15	2.79	2.98	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	**7.25**	**7.55**	"Cash Flow" per sh	**9.55**
1.82	1.82	1.90	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	**3.70**	**3.90**	Earnings per sh A B	**5.00**
1.34	1.35	1.37	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**	**2.46**	Div'ds Decl'd per sh C■	**2.67**
2.67	2.45	2.84	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	**15.30**	**15.40**	Cap'l Spending per sh	**14.90**
15.65	16.96	17.31	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	**49.20**	**52.30**	Book Value per sh D	**54.20**
19.11	20.98	21.17	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	**51.00**	**52.00**	Common Shs Outst'g E	**55.00**
13.6	15.7	16.2	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	*Bold figures are*		Avg Ann'l P/E Ratio	**18.0**
.78	.83	.86	.73	.75	.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.89	*Value Line*		Relative P/E Ratio	**1.00**
5.4%	4.7%	4.4%	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%	*estimates*		Avg Ann'l Div'd Yield	**3.0%**

CAPITAL STRUCTURE as of 6/30/19
Total Debt $2641.3 mill. **Due in 5 Yrs** $599.0 mill.
LT Debt $2042.3 mill. **LT Interest** $100.0 mill.
(Total interest coverage: 2.8x)

Leases, Uncapitalized Annual rentals $9.7 mill.
Pension Assets-9/18 $499.2 mill.
Oblig. $664.6 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $1.6 mill.
Common Stock 50,809,437 shs.
as of 7/26/19

MARKET CAP: $4.1 billion (Mid Cap)

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020		22-24
1895.2	1735.0	1603.3	1125.5	1017.0	1627.2	1976.4	1537.3	1740.7	1965.0	**1980**	**2100**	Revenues ($mill) A	**3000**
64.3	54.0	63.8	62.6	52.8	84.6	136.9	144.2	161.6	214.2	**190**	**200**	Net Profit ($mill)	**275**
33.6%	33.4%	31.4%	29.6%	25.0%	27.6%	31.2%	32.5%	32.4%	32.4%	**23.5%**	**24.0%**	Income Tax Rate	**24.0%**
3.4%	3.1%	4.0%	5.6%	5.2%	5.2%	6.9%	9.4%	9.3%	10.9%	**9.6%**	**9.5%**	Net Profit Margin	**9.2%**
42.9%	40.5%	38.9%	36.1%	46.6%	55.1%	53.0%	50.9%	50.0%	45.7%	**44.0%**	**42.0%**	Long-Term Debt Ratio	**40.0%**
57.1%	59.5%	61.1%	63.9%	53.4%	44.9%	47.0%	49.1%	50.0%	54.3%	**56.0%**	**58.0%**	Common Equity Ratio	**60.0%**
906.3	899.9	937.7	941.0	1959.0	3359.4	3345.1	3601.9	3986.3	4155.5	**4500**	**4700**	Total Capital ($mill)	**4950**
855.9	884.1	928.7	1019.3	1776.6	2759.7	2941.2	3300.9	3665.2	3970.5	**4170**	**4300**	Net Plant ($mill)	**4825**
8.7%	7.4%	8.1%	7.9%	3.3%	3.1%	5.1%	4.9%	5.0%	6.3%	**5.5%**	**5.5%**	Return on Total Cap'l	**7.0%**
12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	**7.5%**	**7.5%**	Return on Shr. Equity	**9.0%**
12.4%	10.1%	11.1%	10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	**7.5%**	**7.5%**	Return on Com Equity	**9.0%**
5.9%	3.6%	4.9%	4.3%	1.0%	1.5%	3.7%	3.3%	3.3%	4.7%	**2.5%**	**2.5%**	Retained to Com Eq	**4.5%**
53%	64%	56%	59%	81%	73%	58%	59%	60%	51%	**64%**	**63%**	All Div'ds to Net Prof	**53%**

CURRENT POSITION ($MILL.)	2017	2018	6/30/19
Cash Assets	7.4	4.4	5.8
Other	718.1	655.2	644.0
Current Assets	725.5	659.6	649.8
Accts Payable	257.1	290.1	297.6
Debt Due	577.3	729.1	599.0
Other	263.5	302.5	323.0
Current Liab.	1097.9	1321.7	1219.6
Fix. Chg. Cov.	361%	284%	300%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	-9.5%	-6.5%	*7.0%*
"Cash Flow"	5.5%	10.5%	*6.0%*
Earnings	4.0%	7.5%	*5.5%*
Dividends	4.0%	5.0%	*4.0%*
Book Value	7.5%	8.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2016	399.4	609.3	249.3	279.3	1537.3
2017	495.1	663.4	323.5	258.7	1740.7
2018	561.8	813.4	350.6	239.2	1965.0
2019	602.0	803.5	321.3	**253.2**	**1980**
2020	**630**	**840**	**370**	**260**	**2100**

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2016	1.08	2.31	.24	d.31	3.24
2017	.99	2.36	.45	d.28	3.43
2018	2.39	2.03	.52	d.51	4.33
2019	1.32	3.04	d.09	**d.57**	**3.70**
2020	**1.35**	**2.60**	**.50**	**d.55**	**3.90**

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.46	.46	.46	.46	1.84
2016	.49	.49	.49	.49	1.96
2017	.525	.525	.525	.525	2.10
2018	.5625	.5625	.5625	.5625	2.25
2019	.5925	.5925	.5925		

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. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2018: 3.3 bill. Revenue mix for regulated operations: residential, 66%; commercial and industrial, 24%; transportation, 6%; other, 4%. Has around 3,366 employees. Officers and directors own 2.9% of common shares; BlackRock, 13% (1/19 proxy). Chairman: Edward Glotzbach; CEO: Suzanne Sitherwood. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

Spire Inc. had a difficult fiscal third quarter (years end September 30th). The top line decreased more than 8% year over year, to $321 million. This was due to weaker revenues in the Gas Utility line, which experienced lesser usage volume and cost recoveries, along with lower gross receipts taxes at both Missouri Utilities and Spire Alabama. Meanwhile, the bottom line registered a per-share deficit of $0.09, versus a per-share profit of $0.52 in the year-ago period. This decline was due to higher total operating expenses, especially from the Spire Marketing unit. On the bright side, Spire was able to reduce its Gas Utility operating costs. On an adjusted basis, share net (or net economic earnings) was $0.07, which was still considerably below the $0.31 figure last year.

The company is actively investing to improve its operations. Spire is upgrading its infrastructure and technology to enhance safety and customer service. Its STL Pipeline is nearing completion and is expected to be ready by the end of this fiscal year. Meanwhile, the company continues to invest in the storage business, which ought to bear fruit in the latter half of fiscal 2020. Management increased the current fiscal year's capital budget by $40 million, to $780 million, reflecting higher spend related to Spire STL Pipeline and Storage. Plus, Spire raised its five-year capital spend target to $2.9 billion, indicating further utility infrastructure upgrades.

Near-term profits will likely remain under pressure. Certainly, the upfront costs associated with the aforementioned initiatives will weigh on the bottom line, but ongoing tight cost controls will probably offset some of these challenges. Nevertheless, profits tend to advance at a measured pace for natural gas utilities, such as Spire. The infrastructure projects should boost customer growth, long term. For now, we estimate share earnings for fiscal 2019 at $3.70, and look for 2020 share net to recover at a single-digit pace.

Neutrally ranked shares of Spire Inc. have below-average long-term capital appreciation potential. Still, a healthy dividend yield and an Above Average (2) rank for Safety may interest some risk-averse and income-oriented accounts.

Emma Jalees *August 30, 2019*

(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 mid-November. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '18: $1171.6 mill., $23.11/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	95
Price Growth Persistence	60
Earnings Predictability	65

UGI CORP. NYSE-UGI

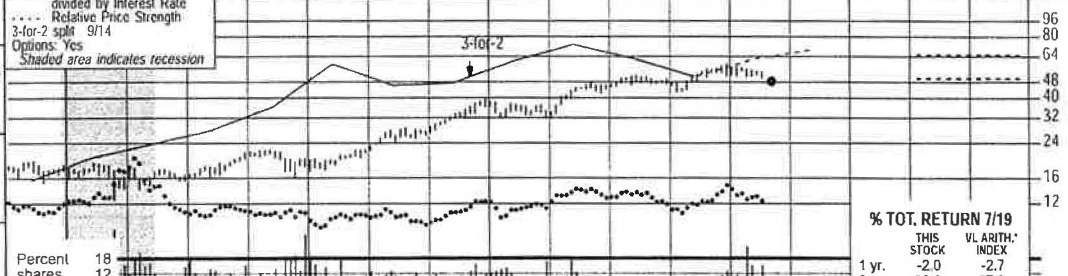
RECENT PRICE 48.48 | P/E RATIO 18.0 (Trailing: 20.9 Median: 16.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 3 Lowered 3/22/19
SAFETY 2 Raised 9/17/04
TECHNICAL 3 Lowered 8/30/19
BETA .80 (1.00 = Market)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
High:	19.2	18.3	21.7	22.4	22.4	28.8	39.7	38.6	48.1	52.0	59.3	57.3
Low:	12.5	14.1	15.9	16.0	17.3	21.9	26.8	31.5	31.6	45.0	42.5	45.9

Target Price Range 2022 | 2023 | 2024

LEGENDS
— 1.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 9/14
Options: Yes
Shaded area indicates recession



2022-24 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	80	(+65%)	15%
Low	60	(+25%)	8%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	1	0
Options	0	6	0	7	1	0	0	1	2
to Sell	0	4	0	0	0	0	0	1	2

Institutional Decisions

	3Q2018	4Q2018	1Q2019
to Buy	222	226	221
to Sell	176	195	202
Hld's(000)	138741	139802	139448

Percent shares traded 18 12 6

% TOT. RETURN 7/19

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.0	-2.7
3 yr.	20.0	27.9
5 yr.	76.5	41.9

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	© VALUE LINE PUB. LLC	22-24
23.62	24.63	31.10	33.01	34.24	41.27	35.25	34.01	36.31	38.56	42.10	47.92	38.65	32.84	35.18	43.94	36.05	45.50	Revenues per sh A	51.15
1.59	1.63	2.09	2.05	2.26	2.48	2.82	2.87	2.75	3.05	3.75	4.05	4.20	4.39	4.73	5.40	5.15	5.30	"Cash Flow" per sh	6.70
.76	.81	1.15	1.10	1.18	1.33	1.57	1.59	1.37	1.17	1.59	1.92	2.01	2.05	2.29	2.74	2.45	3.00	Earnings per sh AB	4.25
.38	.40	.43	.46	.48	.50	.52	.60	.68	.71	.74	.79	.89	.93	.96	1.02	1.12	1.30	Div'ds Decl'd per sh C ■	1.42
.79	.87	1.01	1.21	1.39	1.44	1.85	2.11	2.15	2.01	2.84	2.64	2.83	3.26	3.67	3.30	3.25	3.35	Cap'l Spending per sh	3.55
4.45	5.43	6.35	6.95	8.26	8.80	9.78	11.10	11.79	13.21	14.59	15.39	15.55	16.46	18.18	21.14	27.15	29.10	Book Value per sh D	37.25
128.10	153.63	157.20	158.18	159.97	161.09	162.78	164.38	167.75	169.06	170.88	172.73	173.12	173.15	173.99	174.14	208.00	210.00	Common Shs Outst'g E	210.00
12.6	13.4	13.8	14.0	15.1	13.3	10.3	10.9	15.0	16.4	15.4	15.8	17.7	19.3	20.8	17.8	Bold figures are		Avg Ann'l P/E Ratio	16.0
.72	.71	.73	.76	.80	.80	.69	.69	.94	1.04	.87	.83	.89	1.01	1.05	.96	Value Line		Relative P/E Ratio	.90
3.9%	3.7%	2.7%	3.0%	2.7%	2.9%	3.2%	3.5%	3.3%	3.7%	3.0%	2.6%	2.5%	2.3%	2.0%	2.1%	estimates		Avg Ann'l Div'd Yield	2.4%
						5737.8	5591.4	6091.3	6519.2	7194.7	8277.3	6691.1	5685.7	6120.7	7651.2	7500	9550	Revenues ($mill) A	10745
						258.5	261.0	232.9	199.4	278.1	337.2	353.8	360.0	406.5	485.6	515	635	Net Profit ($mill)	900
						29.4%	32.0%	29.8%	34.8%	27.6%	30.6%	30.0%	31.4%	26.5%	23.0%	22.0%	22.0%	Income Tax Rate	22.0%
						4.5%	4.7%	3.8%	3.1%	3.9%	4.1%	5.3%	6.3%	6.6%	6.3%	6.9%	6.7%	Net Profit Margin	8.4%
						56.2%	44.0%	51.6%	60.0%	58.7%	56.4%	56.1%	56.9%	55.8%	53.0%	51.5%	50.0%	Long-Term Debt Ratio	44.5%
						43.8%	56.0%	48.4%	40.0%	41.3%	43.6%	43.9%	43.1%	44.2%	47.0%	48.5%	50.0%	Common Equity Ratio	55.5%
						3630.0	3256.7	4088.0	5580.7	6034.7	6092.7	6133.8	6616.9	7157.9	7827.9	9795	10310	Total Capital ($mill)	12110
						2903.6	3053.2	3204.5	4233.1	4480.2	4543.7	4994.1	5238.0	5537.0	5808.2	6090	6390	Net Plant ($mill)	7375
						8.9%	10.1%	7.4%	5.6%	6.6%	7.5%	7.7%	7.2%	7.2%	7.7%	5.5%	6.0%	Return on Total Cap'l	7.5%
						16.2%	14.3%	11.8%	8.9%	11.2%	12.7%	13.1%	12.6%	12.9%	13.2%	9.0%	10.5%	Return on Shr. Equity	11.5%
						16.2%	14.3%	11.8%	8.9%	11.2%	12.7%	13.1%	12.6%	12.9%	13.2%	9.0%	10.5%	Return on Com Equity	11.5%
						10.9%	8.9%	6.0%	3.6%	6.1%	7.6%	7.4%	7.0%	7.5%	8.4%	5.0%	7.0%	Retained to Com Eq	7.5%
						33%	38%	49%	60%	45%	40%	43%	45%	42%	36%	45%	43%	All Div'ds to Net Prof	33%

CAPITAL STRUCTURE as of 6/30/19
Total Debt $4689.3 mill. Due in 5 Yrs $839.7 mill.
LT Debt $4291.7 mill. LT Interest $230.1 mill.
(Total interest coverage: 4.0x) (51% of Cap'l)

Leases, Uncapitalized Annual rentals $88.0 mill.
Pension Assets-9/18 $579 mill. Oblig. $688 mill.

Pfd Stock None

Common Stock 174,338,275 shares as of 7/31/19

MARKET CAP: $8.5 bill. (Large Cap)

CURRENT POSITION ($MILL.)	2017	2018	6/30/19
Cash Assets	558.4	452.6	533.7
Other	1139.1	1435.5	1183.9
Current Assets	1697.5	1888.1	1717.6
Accts Payable	439.6	561.8	444.4
Debt Due	544.4	525.3	397.6
Other	706.1	645.0	890.1
Current Liab.	1690.1	1732.1	1732.1
Fix. Chg. Cov.	445%	445%	450%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '16-'18 to '22-'24
Revenues	.5%	-1.0%	5.5%
"Cash Flow"	8.0%	9.0%	5.5%
Earnings	7.0%	11.5%	10.5%
Dividends	7.5%	6.5%	6.5%
Book Value	9.0%	7.0%	12.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2016	1607	1972	1131	976	5685.7
2017	1680	2174	1153	1114	6120.7
2018	2125	2812	1441	1273	7651.2
2019	2200	2606	1364	1330	7500
2020	2710	3115	1875	1850	9550

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2016	.64	1.24	.23	d.05	2.05
2017	.91	1.31	.09	d.02	2.29
2018	1.01	1.69	.09	d.05	2.74
2019	.81	1.43	.13	.08	2.45
2020	.93	1.55	.30	.22	3.00

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2015	.22	.22	.23	.23	.90
2016	.23	.238	.238	.238	.94
2017	.238	.238	.25	.25	.98
2018	.25	.25	.26	.26	1.02
2019	.26	.26	.30		

BUSINESS: UGI Corp. operates six business segments: AmeriGas Propane (accounted for 24.3% of net income in 2018), UGI International (19.3%), Gas Utility (20.7%), Midstream & Marketing (27.4%), and Corp. & Other (8.3%). UGI Utilities distributes natural gas and electricity to over 642,000 customers mainly in Pennsylvania; 26%-owned AmeriGas Partners is the largest U.S. propane marketer, serving about 1.3 million users in 50 states. Acquired remaining 80% interest in Antargaz (3/04); Energy Transfer Partners (1/12). Vanguard Group owns 10.3% of stock; Blackrock, 9.8%; Officers/directors, 2.4% (12/18 proxy). Has 7,700 empls. President & CEO: John L. Walsh. Inc.: PA. Address: 460 N. Gulph Rd., King of Prussia, PA 19406. Tel.: 610-337-1000. Internet: www.ugicorp.com.

UGI Corp. recently finalized its acquisition of AmeriGas Partners, L.P. (APU). That deal has been progressing nicely since it was announced this past spring. UGI already owned 26% of APU units. Existing holders of APU received .50 shares of UGI common stock along with $7.63 in cash. At this point, APU's operations will be considered a wholly owned subsidiary of UGI.

Meanwhile, the company posted mixed June-quarter financial results. To that end, the top line declined 5.4% on a year-over-year basis to $1.364 billion, due to reduced volumes at the AmeriGas Propane and UGI International divisions. This is evident in the general downturn in retail gallons sold for the period. Alternatively, the Midstream & Marketing and UGI Utility segments registered modest top-line gains for the quarter. On the upside, the UGI International unit experienced an almost doubling of its adjusted income. This helped to stem weakness, elsewhere, and on balance, UGI's third-quarter bottom line increased 44.4%, to $0.13 a share. This was a bit lower than our call of earnings of $0.16.

Consequently, we have sliced a nickel off our fiscal 2019 (ends September 30th) share-net estimate, to $2.45. This would represent a year-over-year downturn of more than 10%. It also sits near the lower end of management's guidance range of $2.40-$2.60 per share. UGI appears poised to log a revenue decline of about 2%, to $7.5 billion this year due to warmer-than-normal weather patterns and a general slowing of overall system throughput in many of its divisions.

Prospects appear brighter next year. Along with the APU acquisition, UGI recently completed the purchase of Columbia Midstream Group in early August. Deals like these should bolster UGI's asset base, and coupled with a return to more-normalized weather patterns, ought to turn things around in 2020.

These neutrally ranked shares do not stand out at this juncture. Since our May review, UGI has lost roughly 9.5% of its value. This comes as the company continues to face a challenging operating environment this year. And still, the stock offers below-average appreciation potential.

Bryan J. Fong *August 30, 2019*

(A) Fiscal year ends Sept. 30. Quarterly sales and earnings may not sum to total due to rounding and/or change in share count. (B) Diluted earnings. Excludes nonrecur. gains/(losses): '03, 22¢; '04, d6¢; '05, 3¢; '06, 5¢; '07, 12¢; '15, (41¢); '16, 3¢; '17, 17¢; '18, $1.32. Next egs. report due late Oct. (C) Dividends historically paid in early Jan., April, July, and Oct. ■ Div. reinvest. plan available. (D) Incl. intang. At 9/18: $3,674 mill., $20.77/sh. (E) In mill., adjusted for stock splits.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	90
Earnings Predictability	80

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.

October 11, 2019

TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number

SCREENS

The Median of Estimated
PRICE-EARNINGS RATIOS
of all stocks with earnings

16.6

26 Weeks Ago	Market Low 3-9-09	Market High 7-26-19
17.4	10.3	17.3

The Median of Estimated
DIVIDEND YIELDS
(next 12 months) of all dividend paying stocks under review

2.2%

26 Weeks Ago	Market Low 3-9-09	Market High 7-26-19
2.2%	4.0%	2.2%

The Estimated Median Price
APPRECIATION POTENTIAL
of all 1700 stocks in the Value Line universe in the hypothesized economic environment 3 to 5 years hence

55%

26 Weeks Ago	Market Low 3-9-09	Market High 7-26-19
55%	185%	50%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

*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 LXXV, No. 9.
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PAGE NUMBERS
Bold type refers to Ratings and Reports

	Page	NAME OF STOCK	Ticker Symbol	Recent Price	RANKS 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 3-31-20	(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?
	1170	AptarGroup	ATR	117.67	▼2	2	2	.90	100- 135	(N- 15%)	27.5	1.2	4.28	1.44	41	6/30	1.15	.86	9/30	.36	.34	YES
	976	Aptiv PLC	APTV	85.11	3	3	3	1.30	90- 135	(5- 60%)	18.2	1.0	4.68	.88	82	6/30	1.07	1.10	9/30	.22	.22	YES
	1791	Aqua America	WTR	44.92	3	2	3	.65	40- 55	(N- 20%)	35.7	2.1	1.26	.95	3	6/30	.25	.37	9/30	▲.234	.219	YES
640	1745	ARAMARK Holdings	ARMK	42.68	2	3	3	1.00	50- 75	(15- 75%)	26.7	1.0	1.60	.44	45	6/30	.33	.29	9/30	.11	.105	YES
	319	ArcBest Corp. (NDQ)	ARCB	29.39	4	3	4	1.60	70- 110	(140-275%)	9.4	1.2	3.13	.36	63	6/30	.93	1.12	9/30	.08	.08	YES
	738	ArcelorMittal	MT	13.71	4	3	4	1.75	40- 60	(190-340%)	6.3	1.5	2.19	.20	93	6/30	.26	1.83	9/30	NIL	NIL	YES
	757	Arch Capital Group (NDQ)	ACGL	41.43	1	1	3	.80	40- 50	(N- 20%)	14.5	NIL	2.85	NIL	2	6/30	.77	.59	9/30	NIL	NIL	YES
	1902	Archer Daniels Midl'd	ADM	40.33	3	2	5	1.05	50- 65	(25- 60%)	15.8	3.5	2.55	1.40	46	6/30	.42	1.00	9/30	.35	.335	YES
	1586	Arconic Inc.	ARNC	25.26	1	3	3	1.70	45- 65	(80-155%)	12.2	0.3	2.07	.08	89	6/30	.58	.37	9/30	.02	.06	YES
	2018	Argo Group Int'l	ARGO	70.23	3	2	3	.85	85- 110	(20- 55%)	9.9	1.8	7.07	1.24	12	6/30	.83	1.20	9/30	.31	.27	
	1820	Arista Networks	ANET	230.35	3	3	3	1.15	295- 440	(30- 90%)	25.5	NIL	9.03	NIL	54	6/30	2.33	1.93	9/30	NIL	NIL	YES
	1105	Armstrong World Inds.	AWI	96.47	3	3	2	1.20	85- 125	(N- 30%)	21.1	0.7	4.57	.70	49	6/30	1.28	.90	9/30	.175	NIL	YES
	1323	Arrow Electronics	ARW	72.99	4	3	4	1.35	85- 130	(15- 80%)	10.1	NIL	7.26	NIL	74	6/30	1.60	2.20	9/30	NIL	NIL	YES
	2119	Asbury Automotive	ABG	99.14	▲1	3	3	1.25	95- 140	(N- 40%)	11.0	NIL	9.03	NIL	4	6/30	2.38	2.08	9/30	NIL	NIL	YES
	2199	Ascena Retail Group	ASNA	SEE FINAL REPORT																		
	561	Ashland Global Hldgs.	ASH	75.27	3	3	3	1.05	80- 120	(5- 60%)	38.0	1.5	1.98	1.15	62	6/30	.37	.56	9/30	.275	.25	YES
	775	Assoc. Banc-Corp	ASB	19.70	3	3	4	1.10	30- 45	(50-130%)	10.2	3.5	1.94	.68	47	6/30	.49	.50	9/30	.17	.15	YES
	2545	Assurant Inc.	AIZ	123.81	3	2	3	.85	85- 115	(N- N%)	14.4	1.9	8.57	2.40	13	6/30	2.21	1.09	9/30	.60	.56	YES
	2019	Assured Guaranty	AGO	43.96	2	3	3	1.15	45- 70	(N- 60%)	13.3	1.7	3.31	.76	12	6/30	1.39	.67	9/30	.18	.16	YES
	150	Astec Inds. (NDQ)	ASTE	30.26	▼4	3	4	1.30	55- 85	(80-180%)	12.8	1.5	2.37	.44	59	6/30	.36	1.03	9/30	.11	.11	YES
	1616	AstraZeneca PLC (ADS)	AZN	43.66	3	3	2	.90	45- 65	(5- 50%)	49.6	3.2	.88	1.40	68	6/30	.05	.14	9/30	.45	.45	YES
228	704	Astronics Corp. (NDQ)	ATRO	29.14	4	3	4	1.25	50- 75	(70-155%)	19.2	NIL	1.52	NIL	44	6/30	.20	.43	9/30	NIL	NIL	
	2164	At Home Group	HOME	9.82	4	4	5	1.30	19- 30	(95-205%)	11.3	NIL	.87	NIL	91	7/31	.16	d.16	9/30	NIL	NIL	YES
	2020	Athene Holding Ltd.	ATH	40.42	–	3	–	NMF	60- 95	(50-135%)	5.5	NIL	7.40	NIL	12	6/30	1.95	1.48	9/30	NIL	NIL	YES
	305	Atlas Air Worldwide (NDQ)	AAWW	23.59	5	3	3	1.50	55- 80	(135-240%)	4.7	NIL	4.97	NIL	65	6/30	.17	1.75	9/30	NIL	NIL	YES
	548	Atmos Energy	ATO	112.98	3	1	3	.60	115- 140	(N- 25%)	25.8	2.0	4.38	2.24	52	6/30	.68	.64	9/30	.525	.485	YES
	943	AudioCodes Ltd. (NDQ)	AUDC	18.40	1	4	3	1.00	17- 30	(N- 65%)	21.1	1.3	.87	.24	28	6/30	.22	.14	9/30	.12	.20	YES
	1617	Aurora Cannabis	ACB	4.12	–	4	–	NMF	16- 25	(290-505%)	NMF	NIL	d.10	NIL	68	6/30	NIL	NA	12/31	NIL	NIL	YES
847	2591	Autodesk, Inc. (NDQ)	ADSK	145.71	3	3	2	1.35	145- 215	(N- 50%)	91.1	NIL	1.60	NIL	19	7/31	.18	d.18	9/30	NIL	NIL	YES
	977	Autoliv, Inc.	ALV	76.06	–	3	–	NMF	115- 175	(50-130%)	12.7	3.3	5.98	2.48	82	6/30	1.25	2.20	12/31	.62	.62	YES
	2619	Automatic Data Proc. (NDQ)	ADP	160.43	2	1	2	1.05	175- 215	(10- 35%)	28.4	2.2	5.65	3.46	1	6/30	1.09	.25	12/31	.79	.69	YES
	2120	AutoNation, Inc.	AN	50.31	3	3	3	1.10	70- 105	(40-110%)	11.3	NIL	4.45	NIL	4	6/30	1.12	1.07	9/30	NIL	NIL	YES
	2121	AutoZone Inc.	AZO	1083.67	1	3	2	.80	1020-1530	(N- 40%)	17.1	NIL	63.44	NIL	4	8/31	22.59	18.54	9/30	NIL	NIL	YES
229	1821	Avalara, Inc.	AVLR	66.60	–	3	–	NMF	75- 115	(15- 75%)	NMF	NIL	▲d.46	NIL	54	6/30	d.18	d.27	9/30	NIL	NIL	YES
	1515	AvalonBay Communities	AVB	214.00	3	2	3	.70	205- 280	(N- 30%)	35.8	3.0	5.97	6.35	33	6/30	1.21	1.84	12/31	1.52	1.47	YES
	136	AVANGRID, Inc.	AGR	51.93	3	2	4	.40	45- 60	(N- 15%)	22.8	3.4	2.28	1.76	14	6/30	.36	.34	12/31	.44	.44	YES
	198	Avanos Medical	AVNS	35.93	–	3	–	1.20	45- 70	(25- 95%)	27.6	NIL	1.30	NIL	31	6/30	.28	.03	9/30	NIL	NIL	YES
	562	Avery Dennison	AVY	111.66	3	2	1	1.00	125- 165	(10- 50%)	16.6	2.2	6.74	2.44	62	6/30	1.72	1.07	9/30	.58	.52	YES
	2165	Avis Budget Group (NDQ)	CAR	27.25	3	4	4	1.55	45- 70	(65-155%)	6.8	NIL	3.98	NIL	91	6/30	.79	.57	9/30	NIL	NIL	YES
	2219	Avista Corp.	AVA	48.57	3	2	4	.60	40- 55	(N- 15%)	24.4	3.3	1.99	1.58	50	6/30	.38	.39	9/30	.388	.373	YES
	1324	Avnet, Inc. (NDQ)	AVT	43.71	3	3	3	1.25	55- 85	(25- 95%)	13.2	1.9	3.30	.84	74	6/30	.95	.99	9/30	▲.21	.20	YES
	1006	Avon Products	AVP	4.32	–	5	–	1.70	3- 6	(N- 40%)	20.6	NIL	.21	NIL	78	6/30	.06	d.03	9/30	NIL	NIL	YES
	563	Axalta Coating	AXTA	29.73	–	3	–	1.00	35- 50	(20- 70%)	20.6	NIL	1.44	NIL	62	6/30	.42	.31	9/30	NIL	NIL	YES
	2021	AXIS Capital Hldgs.	AXS	66.35	3	2	3	.85	65- 85	(N- 30%)	12.2	2.4	5.42	1.60	12	6/30	1.62	1.27	12/31	.40	.40	YES
448	705	Axon Enterprise (NDQ)	AAXN	54.22	4	4	2	1.30	35- 55	(N- N%)	NMF	NIL	.49	NIL	44	6/30	.01	.15	9/30	NIL	NIL	YES
	1903	B&G Foods	BGS	18.76	4	3	3	.60	45- 70	(140-275%)	9.1	10.3	2.06	1.94	46	6/30	.38	.38	12/31	.475	.475	YES
	2503	BB&T Corp.	BBT	52.34	2	2	4	1.05	55- 80	(5- 55%)	12.3	3.4	4.24	1.80	37	6/30	1.09	.99	9/30	▲.45	.405	YES
	1028	BCE Inc.	BCE	48.52	1	2	3	.75	45- 60	(N- 25%)	17.4	5.0	2.79	2.44	26	6/30	.71	.65	12/31	.599	.59	YES
	1799	BGC Partners (NDQ)	BGCP	5.32	–	3	–	NMF	7- 11	(30-105%)	7.9	10.5	.67	.56	21	6/30	.17	.17	9/30	.14	.18	YES
	1587	BHP Group Ltd. ADR	BHP	49.01	3	3	3	1.30	65- 100	(35-105%)	13.6	5.5	3.60	2.70(h)	89	6/30	1.80(p)	1.74(p)	9/30	1.56	1.26	YES
	351	BJ's Restaurants (NDQ)	BJRI	37.88	4	3	4	.85	90- 135	(140-255%)	18.5	1.3	2.05	.48	32	6/30	.68	.79	9/30	.12	.11	YES
640	2135	BJ's Wholesale Club	BJ	25.13	–	4	–	NMF	30- 50	(20-100%)	16.5	NIL	1.52	NIL	57	7/31	.39	d.05	9/30	NIL	NIL	YES
	776	BOK Financial (NDQ)	BOKF	76.83	3	3	4	1.20	105- 155	(35-100%)	10.0	2.6	7.65	2.00	47	6/30	1.93	1.75	9/30	.50	.50	YES
	502	BP PLC ADR	BP	37.70	3	3	5	1.25	60- 90	(60-140%)	12.2	6.5	3.08	2.46	53	6/30	.54	.84	9/30	.615	.615	YES
1421	1029	BT Group ADR(g)	BTTGY	SEE FINAL SUPPLEMENT																		
	1209	BWX Technologies	BWXT	55.91	3	3	3	1.05	60- 90	(5- 60%)	21.2	1.2	2.64	.68	27	6/30	.62	.60	9/30	.17	.16	YES
	114	Badger Meter	BMI	53.20	3	3	3	1.00	50- 70	(N- 30%)	33.3	1.3	1.60	.68	35	6/30	.39	.42	9/30	▲.17	.15	YES
	2641	Baidu, Inc. (NDQ)	BIDU	102.00	5	3	3	1.35	240- 360	(135-255%)	12.9	NIL	7.90	NIL	55	6/30	.96	2.74	9/30	NIL	NIL	YES
	2418	Baker Hughes, a GE co.	BHGE	22.67	–	3	–	NMF	35- 55	(55-145%)	27.0	3.2	.84	.72	96	6/30	d.02	d.05	9/30	.18	.18	YES
	564	Balchem Corp. (NDQ)	BCPC	98.18	3	3	3	1.05	115- 170	(15- 75%)	38.2	0.5	2.57	.47	62	6/30	.61	.61	9/30	NIL	NIL	YES
	1171	Ball Corp.	BLL	72.11	3	2	1	1.00	95- 125	(30- 75%)	27.9	0.8	2.58	.60	41	6/30	.58	.34	9/30	.15	.10	YES
	2504	BancorpSouth Bank	BXS	28.93	3	3	4	1.15	35- 55	(20- 90%)	12.6	2.6	2.30	.74	37	6/30	.53	.55	12/31	▲.185	.17	YES
	2505	Bank of America	BAC	28.44	3	3	3	1.25	35- 55	(25- 95%)	9.9	2.5	2.87	.72	37	6/30	.74	.63	9/30	▲.18	.15	YES
	2506	Bank of Hawaii	BOH	83.87	2	2	2	1.00	95- 130	(15- 55%)	14.4	3.1	5.82	2.60	37	6/30	1.40	1.30	9/30	.65	.60	YES
	2507	Bank of Montreal (TSE)	BMO.TO	96.97b	3	2	5	.80	125- 165	(30- 70%)	9.9	4.4	9.83	4.29	37	7/31	2.34(b)	2.31(b)	12/31	1.03(b)	.96(b)	YES
	2508	Bank of New York Mellon	BK	43.73	3	2	4	1.10	80- 110	(85-150%)	11.0	2.8	3.96	1.24	37	6/30	1.01	1.03	9/30	▲.31	.28	YES
	2509	Bank of Nova Scotia (TSE)	BNS.TO	74.60b	2	1	5	.85	95- 115	(25- 55%)	10.3	4.8	7.23	3.60	37	7/31	1.88(b)	1.76(b)	12/31	▲.90(b)	.85(b)	YES
227	2166	Barnes & Noble	BKS	SEE FINAL SUPPLEMENT																		
	1746	Barnes Group	B	49.86	4	3	4	1.20	70- 105	(40-110%)	15.4	1.3	3.23	.64	45	6/30	.73	.93	9/30	.16	.16	YES
	1649	Barrett Business Serv. (NDQ)	BBSI	86.30	3	4	2	1.10	100- 165	(15- 90%)	15.8	1.4	5.46	1.20	75	6/30	1.81	1.46	9/30	.30	.25	YES
	1573	Barrick Gold	GOLD	17.22	1	4	2	.65	14- 25	(N- 45%)	31.9	0.9	.54	.16	15	6/30	.09	.07	9/30	.04	.03	YES
★★	1618	Bausch Health	BHC	19.67	3	5	2	1.35	25- 50	(25-155%)	4.7	NIL	4.16	NIL	68	6/30	1.04	.93	9/30	NIL	NIL	YES
	170	Baxter Int'l Inc.	BAX	85.91	3	1	2	.90	90- 110	(5- 30%)	25.0	1.0	3.43	.88	16	6/30	.89	.77	12/31	.22	.19	YES
229	1106	Beacon Roofing (NDQ)	BECN	31.39	4	3	3	1.15	25- 40	(N- 25%)	NMF	NIL	d.22	NIL	49	6/30	.32	.63	9/30	NIL	NIL	YES
	1125	Beazer Homes USA	BZH	14.66	4	5	4	1.65	12- 25	(N- 70%)	11.8	NIL	1.24	NIL	24	6/30	.24	.41	9/30	NIL	NIL	YES
	171	Becton, Dickinson	BDX	250.64	2	1	1	.85	305- 375	(20- 50%)	20.1	1.3	12.46	3.14	16	6/30	3.08	2.91	9/30	.77	.75	YES
	2167	Bed Bath & Beyond (NDQ)	BBBY	10.32	5	3	4	1.05	17- 25	(65-140%)	NMF	6.6	d.95	.68	91	5/31	d2.91	.32	12/31	.17	.16	YES
	1303	Belden Inc.	BDC	52.65	4	3	4	1.55	75- 115	(40-120%)	13.2	0.4	3.98	.20	66	6/30	.84	.49	12/31	.05	.05	YES
	1325	Benchmark Electronics	BHE	28.78	3	3	3	1.00	35- 50	(20- 75%)	19.2	2.1	1.50	.60	74	6/30	.36	.30	12/31	.15	.15	YES
	758	Berkley (W.R.)	WRB	71.11	1	1	3	.85	60- 75	(N- 5%)	24.5	0.6	2.90	.44	2	6/30	.82	.65	12/31	.11	.10	YES
	759	Berkshire Hathaway 'B'	BRKB	206.71	3	1	3	.95	215- 265	(5- 30%)	20.0	NIL	10.34	NIL	2	6/30	2.50	2.79	9/30	NIL	NIL	YES
2661	1172	Berry Global Group	BERY	38.15	4	3	3	1.00	55- 85	(45-125%)	10.6	NIL	3.59	NIL	41	6/30	.90	.96	9/30	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 3-31-20, 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 Ratings and Reports

Page	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 3-31-20	(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?
	1792	California Water		CWT	52.74	3	3	2	.70	35- 55	(N- 5%)	33.2	1.5	1.59	.79	3	6/30	.35	.31	9/30	.198	.188	YES
	944	Calix, Inc.		CALX	6.10	5	4	4	1.15	12- 20	(95-230%)	61.0	NIL	.10	NIL	28	6/30	d.01	.01	9/30	NIL	NIL	YES
	2305	Callaway Golf		ELY	18.93	3	3	3	1.00	25- 40	(30-110%)	21.8	0.2	.87	.04	36	6/30	.37	.63	9/30	.01	.01	YES
2231	528	Callon Petroleum		CPE	4.01	–	4	–	2.10	20- 35	(400-775%)	3.9	NIL	1.04	NIL	92	6/30	.23	.23	9/30	NIL	NIL	YES
229	834	Cambrex Corp.		CBM	59.54	–	3	–	1.20	65- 95	(10- 60%)	31.3	NIL	1.90	NIL	71	6/30	.49	.74	9/30	NIL	NIL	YES
	1517	Camden Property Trust		CPT	110.57	3	3	3	.70	95- 145	(N- 30%)	63.2	2.9	1.75	3.20	33	6/30	.40	.40	12/31	.80	.77	YES
	1588	Cameco Corp.	(TSE)	CCO.TO	12.23b	3	3	5	1.20	17- 25	(40-105%)	NMF	0.7	.09	.08	89	6/30	d.04(b)	d.07(b)	9/30	NIL(b)	NIL(b)	YES
1037	1908	Campbell Soup		CPB	46.82	3	2	3	.65	40- 50	(N- 5%)	17.9	3.0	2.62	1.40	46	7/31	.49	.25	12/31	◆.35	.35	YES
	2122	Camping World Holdings		CWH	8.91	5	4	4	1.80	30- 50	(235-460%)	4.5	3.6	1.97	.32	4	6/30	.54	.87	9/30	.08	.08	YES
	2102	Canada Goose Hldgs.	(TSE)	GOOS.TO	53.77	–	3	–	NMF	90- 135	(65-150%)	31.6	NIL	1.70	NIL	80	6/30	d.21	d.16	9/30	NIL	NIL	
	2510	Can. Imperial Bank	(TSE)	CM.TO	108.76b	3	1	5	.85	130- 160	(20- 45%)	9.0	5.3	12.15	5.78	37	7/31	3.06(b)	3.01(b)	12/31	▲1.44(b)	1.36(b)	YES
	340	Can. National Railway		CNI	86.74	2	2	1	1.05	100- 135	(15- 55%)	17.6	1.9	4.94	1.64	25	6/30	1.29	1.17	9/30	.409	.351	YES
	2403	Can. Natural Res.	(TSE)	CNQ.TO	34.10b	4	3	3	1.45	60- 85	(75-150%)	11.4	4.4	3.00	1.50	95	6/30	.87(b)	1.04(b)	12/31	.375(b)	.335(b)	YES
	341	Can. Pacific Railway		CP	217.22	2	3	2	1.20	260- 390	(20- 80%)	16.2	1.2	13.40	2.56	25	6/30	3.20	2.36	12/31	▲.636	.499	YES
	2138	Canadian Tire 'A'	(TSE)	CTCA.TO	147.49b	2	2	5	.70	185- 250	(25- 70%)	13.1	2.8	11.28	4.15	57	6/30	2.87(b)	2.38(b)	12/31	1.036(b)	1.037(b)	YES
2673	1621	CannTrust Holdings		CTST		SEE LATEST REPORT																	
	1983	Canon Inc. ADR(g)		CAJ	26.81	3	1	4	.85	50- 60	(85-125%)	16.0	5.1	1.68	1.38	60	6/30	.29	.65	9/30	.659	.641	YES
449	1622	Canopy Growth Corp.		CGC	21.83	–	4	–	NMF	40- 70	(85-220%)	NMF	NIL	d3.35	NIL	68	6/30	d2.77	d.30	9/30	NIL	NIL	YES
	200	Cantel Medical Corp.		CMD	72.38	3	3	3	.90	95- 145	(30-100%)	31.6	0.3	2.29	.24	31	7/31	.21	.41	9/30	.10	.085	YES
	2550	Capital One Fin'l		COF	89.07	3	3	3	1.20	100- 150	(10- 70%)	7.7	1.8	11.55	1.60	13	6/30	3.24	3.73	9/30	.40	.40	YES
	1502	Capitol Fed. Fin'l	(NDQ)	CFFN	13.66	3	2	2	.75	14- 20	(N- 45%)	19.2	2.5	.71	.34	8	6/30	.17	.17	9/30	.085	.085	YES
	2103	Capri Holdings Ltd.		CPRI	31.44	5	3	4	1.05	70- 105	(125-235%)	7.1	NIL	4.40	NIL	80	6/30	.30	1.22	9/30	NIL	NIL	YES
	201	Cardinal Health		CAH	47.28	3	3	4	1.10	75- 115	(60-145%)	11.4	4.1	4.15	1.92	31	6/30	.65	d3.69	12/31	.481	.476	YES
	1999	Career Education	(NDQ)	CECO	16.00	2	4	1	1.15	20- 35	(25-120%)	14.0	NIL	1.14	NIL	10	6/30	.39	.12	9/30	NIL	NIL	YES
	1749	Carlisle Cos.		CSL	142.04	2	2	2	1.00	170- 225	(20- 60%)	17.0	1.4	8.37	2.00	45	6/30	2.65	1.87	9/30	▲.50	.40	YES
	2454	Carlyle Group L.P.	(NDQ)	CG	24.96	2	3	3	1.25	25- 40	(N- 60%)	11.2	6.9	2.22	1.72	5	6/30	1.23	.56	9/30	.43	.22	YES
	2123	CarMax, Inc.		KMX	88.69	2	3	3	1.20	100- 150	(15- 70%)	16.7	NIL	5.30	NIL	4	8/31	1.40	1.24	9/30	NIL	NIL	YES
1660	2306	Carnival Corp.		CCL	42.49	3	3	3	1.05	90- 130	(110-205%)	9.5	4.7	4.47	2.00	36	8/31	◆2.58	2.41	9/30	.50	.50	YES
	739	Carpenter Technology		CRS	50.40	3	3	3	1.65	70- 110	(40-120%)	13.3	1.6	3.80	.80	93	6/30	1.00	.88	9/30	.20	.20	YES
	1845	Carriage Services		CSV	20.62	3	3	3	.85	30- 50	(45-140%)	15.4	1.5	1.34	.30	85	6/30	.27	.15	9/30	.075	.075	YES
	2104	Carter's Inc.		CRI	90.60	3	3	3	.90	135- 200	(50-120%)	13.5	2.2	6.70	2.00	80	6/30	.97	.79	9/30	.50	.45	YES
	945	Casa Systems	(NDQ)	CASA	7.12	–	4	–	NMF	6- 10	(N- 40%)	39.6	NIL	.18	NIL	28	6/30	.01	.23	9/30	NIL	NIL	YES
	1947	Casey's Gen'l Stores	(NDQ)	CASY	161.58	1	3	1	.75	120- 180	(N- 10%)	27.6	0.8	5.85	1.28	22	7/31	2.31	1.90	12/31	.32	.29	YES
	173	Catalent, Inc.		CTLT	47.21	3	3	1	1.10	55- 85	(15- 80%)	44.1	NIL	1.07	NIL	16	6/30	.44	.61	9/30	NIL	NIL	YES
2459	152	Caterpillar Inc.		CAT	122.37	4	2	3	1.30	215- 290	(75-135%)	10.3	3.4	11.91	4.12	59	6/30	2.83	2.97	9/30	▲1.03	.86	YES
	2201	Cato Corp.		CATO	17.43	3	3	4	.85	20- 30	(15- 70%)	15.4	7.6	1.13	1.32	79	7/31	.48	.26	9/30	.33	NIL	YES
	2307	Cedar Fair L.P.		FUN	58.20	2	3	4	.75	80- 120	(35-105%)	17.2	6.4	3.39	3.70	36	6/30	1.11	.34	9/30	.925	.89	YES
	2443	Celanese Corp.		CE	120.35	3	3	2	1.30	120- 180	(N- 50%)	11.2	2.1	10.73	2.48	83	6/30	2.38	2.90	9/30	.62	.54	YES
	1327	Celestica Inc.		CLS	6.94	4	3	4	.90	9- 13	(30- 85%)	16.1	NIL	.43	NIL	74	6/30	.12	.11	9/30	NIL	NIL	YES
	1623	Celgene Corp.	(NDQ)	CELG	99.26	–	3	–	1.25	125- 190	(25- 90%)	13.8	NIL	7.21	NIL	68	6/30	2.16	1.43	9/30	NIL	NIL	YES
	1109	CEMEX ADS		CX	3.80	4	4	3	1.55	8- 14	(110-270%)	5.9	NIL	.64	NIL	49	6/30	.10	.25	9/30	NIL	NIL	YES
	504	Cenovus Energy	(TSE)	CVE.TO	12.05b	3	3	3	1.35	16- 25	(35-105%)	17.0	2.1	.71	.25	53	6/30	.22(b)	d.33(b)	12/31	▲.063(b)	.05(b)	YES
	794	Centene Corp.		CNC	42.75	3	3	3	1.05	80- 115	(85-170%)	9.3	NIL	4.61	NIL	40	6/30	1.34	.90	9/30	NIL	NIL	YES
	529	Centennial Resource Dev.	(NDQ)	CDEV	4.08	5	4	3	1.80	15- 25	(270-515%)	12.4	NIL	.33	NIL	92	6/30	.07	.24	9/30	NIL	NIL	YES
	907	CenterPoint Energy		CNP	29.89	3	3	3	.80	25- 40	(N- 35%)	17.9	3.9	1.67	1.18	42	6/30	.33	d.17	9/30	.288	.278	YES
	421	Central & East. Europe		CEE	26.04	–	4	–	1.00	25- 40	(N- 55%)	NMF	1.9	NMF	.50	–	4/30	28.43(q)	27.78(q)	9/30	NIL	NIL	
	1184	Central Garden & Pet	(NDQ)	CENT	29.19	3	3	5	.85	55- 85	(90-190%)	15.4	NIL	1.89	NIL	39	6/30	.80	.79	9/30	NIL	NIL	YES
	1589	Century Aluminum	(NDQ)	CENX	6.49	5	4	4	2.30	10- 17	(55-160%)	NMF	NIL	d.08	NIL	89	6/30	d.18	.20	9/30	NIL	NIL	YES
	1030	CenturyLink Inc.		CTL	12.13	4	3	5	1.05	13- 20	(5- 65%)	9.1	8.2	1.34	1.00	26	6/30	.34	.26	9/30	.25	.54	YES
	821	Cerner Corp.	(NDQ)	CERN	67.46	1	2	1	.95	75- 100	(10- 50%)	23.8	1.1	2.84	.72	70	6/30	.66	.62	12/31	.18	NIL	YES
	202	Charles River		CRL	128.16	3	3	3	1.10	125- 185	(N- 45%)	26.5	NIL	4.84	NIL	31	6/30	.88	1.06	9/30	NIL	NIL	YES
	727	Chart Industries	(NDQ)	GTLS	60.28	3	3	3	1.70	65- 100	(10- 65%)	21.5	NIL	2.81	NIL	67	6/30	.68	.32	9/30	NIL	NIL	YES
	1019	Charter Communic.	(NDQ)	CHTR	405.60	2	3	2	1.05	290- 435	(N- 5%)	52.4	NIL	7.74	NIL	17	6/30	1.39	1.15	9/30	NIL	NIL	YES
	1823	Check Point Software	(NDQ)	CHKP	107.43	3	1	3	.85	125- 155	(15- 45%)	19.0	NIL	5.65	NIL	54	6/30	1.21	1.24	9/30	NIL	NIL	YES
	354	Cheesecake Factory	(NDQ)	CAKE	41.42	3	2	5	.75	65- 85	(55-105%)	15.6	3.5	2.66	1.44	32	6/30	.82	.65	9/30	▲.36	.33	YES
	1948	Chefs' Warehouse	(NDQ)	CHEF	39.85	3	3	3	1.00	30- 50	(N- 25%)	41.9	NIL	.95	NIL	22	6/30	.26	.24	9/30	NIL	NIL	YES
	1750	Chemed Corp.		CHE	411.24	1	2	2	.85	▲ 375- 510	(N- 25%)	28.9	0.3	14.23	1.28	45	6/30	3.36	2.81	9/30	▲.32	.30	YES
	2660	Chemical Financial		CHFC		SEE FINAL SUPPLEMENT																	
229	566	Chemours Co. (The)		CC	13.98	5	4	3	2.05	35- 50	(150-260%)	5.4	7.2	2.60	1.00	62	6/30	.57	1.53	9/30	.25	.25	YES
	610	Cheniere Energy Inc.	(ASE)	LNG	63.00	3	3	3	1.35	95- 145	(50-130%)	44.7	NIL	1.41	NIL	29	6/30	d.44	d.07	9/30	NIL	NIL	YES
	623	Cheniere Energy Part.		CQP	44.58	3	3	2	1.05	50- 75	(10- 70%)	17.1	5.9	2.61	2.62	18	6/30	.44	.55	9/30	▲.61	.56	YES
	530	Chesapeake Energy		CHK	1.33	–	5	–	2.50	8- 15	(NMF)	4.8	NIL	.28	NIL	92	6/30	.05	d.04	9/30	NIL	NIL	YES
	549	Chesapeake Utilities		CPK	94.77	3	2	2	.65	100- 140	(5- 50%)	26.3	1.7	3.61	1.65	52	6/30	.50	.39	12/31	.405	.37	YES
230	505	Chevron Corp.		CVX	116.01	3	1	3	1.20	130- 155	(10- 35%)	15.8	4.1	7.36	4.79	53	6/30	1.78	1.78	9/30	1.19	1.12	YES
	2202	Chico's FAS		CHS	3.97	–	4	–	.85	9- 16	(125-305%)	66.2	9.1	.06	.36	79	7/31	d.02	.13	9/30	.088	.085	YES
	2203	Children's Place	(NDQ)	PLCE	76.49	4	3	4	.80	150- 225	(95-195%)	12.3	2.9	6.24	2.24	79	7/31	.19	.70	12/31	.56	.50	YES
	422	China Fund (The)		CHN	19.15	–	3	–	.90	20- 30	(5- 55%)	NMF	0.5	NMF	.10	–	4/30	23.63(q)	24.05(q)	9/30	NIL	NIL	
	920	China Mobile (ADR)		CHL	41.53	3	3	4	.85	50- 80	(20- 95%)	11.5	4.6	3.60	1.90	43	6/30	1.94(p)	2.43(p)	9/30	.89	1.17	YES
	355	Chipotle Mex. Grill		CMG	828.84	1	3	2	.95	580- 870	(N- 5%)	59.5	NIL	13.92	NIL	32	6/30	3.92	2.87	9/30	NIL	NIL	YES
	2351	Choice Hotels Int'l		CHH	88.71	3	3	2	1.00	65- 100	(N- 15%)	21.8	1.0	4.06	.86	56	6/30	1.33	1.40	12/31	.215	.215	YES
	761	Chubb Ltd.		CB	158.63	3	1	3	.90	190- 230	(20- 45%)	14.7	1.9	10.76	3.00	2	6/30	2.60	2.68	12/31	.75	.73	YES
	1185	Church & Dwight		CHD	75.56	2	1	2	.75	65- 80	(N- 5%)	31.5	1.2	2.40	.91	39	6/30	.55	.49	9/30	.228	.218	YES
	2352	Churchill Downs	(NDQ)	CHDN	122.97	2	2	2	1.05	105- 145	(N- 20%)	28.6	0.5	4.30	.57	56	6/30	2.63	2.52	9/30	NIL	NIL	YES
	946	Ciena Corp.		CIEN	36.49	1	4	1	1.30	55- 95	(50-160%)	16.8	NIL	2.17	NIL	28	7/31	.71	.48	9/30	NIL	NIL	YES
2026	795	Cigna Corp.		CI	150.43	3	3	4	.95	255- 385	(70-155%)	8.7	NIL	17.30	.04	40	6/30	4.30	3.89	9/30	NIL	NIL	YES
	531	Cimarex Energy		XEC	45.32	3	3	4	1.50	115- 175	(155-285%)	8.6	1.8	5.30	.80	92	6/30	.82	1.59	12/31	.20	.18	YES
	2374	Cimpress N.V.	(NDQ)	CMPR	128.99	▲2	3	4	.90	85- 130	(N- N%)	58.9	NIL	2.19	NIL	90	6/30	1.09	d.24	9/30	NIL	NIL	YES
	1031	Cincinnati Bell		CBB	4.87	–	4	–	1.55	6- 9	(25- 85%)	NMF	NIL	d.57	NIL	26	6/30	d.13	d.19	9/30	NIL	NIL	YES
	762	Cincinnati Financial	(NDQ)	CINF	114.20	1	2	3	.90	75- 105	(N- N%)	29.7	2.0	3.85	2.24	2	6/30	.85	.81	12/31	.56	.53	YES
	2308	Cinemark Hldgs.		CNK	38.42	2	3	3	1.05	60- 85	(55-120%)	15.6	3.6	2.47	1.40	36	6/30	.86	.70	9/30	.34	.32	YES
	384	Cintas Corp.	(NDQ)	CTAS	262.39	2	2	2	1.00	220- 300	(N- 15%)	31.8	0.9	8.25	2.25	7	8/31	2.32	1.93	9/30	NIL	NIL	YES
	1357	Cirrus Logic	(NDQ)	CRUS	52.95	3	3	2	.95	60- 90	(15- 70%)	19.3	NIL	2.75	NIL	73	6/30	.35	.28	9/30	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 3-31-20, 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 Ratings and Reports

Page	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 3-31-20	(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?
	217	Meridian Bioscience	(NDQ)	VIVO	9.25	5	4	4	.70	19- 30	(105-225%)	13.2	NIL	.70	NIL	31	6/30	.16	.18	9/30	NIL	.125	YES
	994	Meritor, Inc.		MTOR	17.86	3	4	3	1.45	30- 50	(70-180%)	5.1	NIL	3.53	NIL	82	6/30	1.20	.89	9/30	NIL	NIL	YES
	1130	Meritage Homes		MTH	70.26	3	3	3	1.30	75- 110	(5- 55%)	12.4	NIL	5.65	NIL	24	6/30	1.31	1.31	9/30	NIL	NIL	YES
	580	Methanex Corp.	(NDQ)	MEOH	34.46	5	3	4	1.65	65- 100	(90-190%)	15.9	4.2	2.17	1.46	62	6/30	.34	1.75	9/30	.36	.33	YES
	1337	Methode Electronics		MEI	32.63	3	3	3	1.50	45- 70	(40-115%)	9.7	1.3	3.35	.44	74	7/31	.75	.63	12/31	.11	.11	YES
	1563	MetLife Inc.		MET	46.03	3	3	3	1.30	55- 80	(20- 75%)	7.9	3.9	5.80	1.78	20	6/30	1.38	1.30	9/30	.44	.42	YES
	1954	Metro Inc.	(TSE)	MRU.TO	57.63b	▲1	2	3	.55	50- 70	(N- 20%)	19.1	1.4	3.01	.80	22	6/30	.90(b)	.75(b)	12/31	◆.20(b)	.18(b)	YES
	126	Mettler-Toledo Int'l		MTD	688.14	2	2	2	1.10	560- 760	(N- 10%)	30.7	NIL	22.38	NIL	35	6/30	5.06	4.31	9/30	NIL	NIL	YES
	427	Mexico Fund		MXF	12.99	–	4	–	1.05	16- 25	(25- 90%)	NMF	1.2	NMF	.15	–	7/31	14.62(q)	19.23(q)	9/30	.047	NIL	
1038	2179	Michaels Cos. (The)	(NDQ)	MIK	9.72	5	3	5	1.15	35- 55	(260-465%)	4.1	NIL	2.39	NIL	91	7/31	.19	.15	9/30	NIL	NIL	YES
	1368	Microchip Technology	(NDQ)	MCHP	92.92	3	3	3	1.25	125- 185	(35-100%)	16.0	1.6	5.80	1.50	73	6/30	1.41	1.61	9/30	.366	.364	YES
★★	1369	Micron Technology	(NDQ)	MU	42.30	3	3	3	1.70	65- 100	(55-135%)	15.8	NIL	2.67	NIL	73	8/31	◆.56	3.53	9/30	NIL	NIL	YES
2461	2599	Microsoft Corp.	(NDQ)	MSFT	137.07	1	1	2	1.10	150- 185	(10- 35%)	27.0	1.5	5.07	2.04	19	6/30	1.37	1.13	12/31	▲.51	.46	YES
	1537	Mid-America Apartment		MAA	129.98	▼2	2	3	.70	100- 150	(N- 15%)	57.0	3.0	2.28	3.84	33	6/30	.53	.52	12/31	◆.96	.923	YES
	1722	Middleby Corp. (The)	(NDQ)	MIDD	114.29	2	3	3	1.10	165- 250	(45-120%)	16.6	NIL	6.87	NIL	23	6/30	1.70	1.57	9/30	NIL	NIL	YES
	1795	Middlesex Water	(NDQ)	MSEX	64.37	3	2	3	.70	45- 60	(N- N%)	32.0	1.5	2.01	.96	3	6/30	.49	.52	9/30	.24	.224	YES
2234	1723	Milacron Holdings		MCRN	16.52	–	4	–	1.40	19- 30	(15- 80%)	11.6	NIL	1.43	NIL	23	6/30	.34	.48	9/30	NIL	NIL	YES
	1155	Miller (Herman)	(NDQ)	MLHR	45.14	2	3	3	1.20	50- 75	(10- 65%)	14.1	1.8	3.21	.79	51	8/31	.84	.69	9/30	.198	.18	YES
	581	Minerals Techn.		MTX	51.31	4	3	3	1.50	80- 125	(55-145%)	12.2	0.4	4.19	.20	62	6/30	1.11	1.24	9/30	.05	.05	YES
	398	Mobile Mini	(NDQ)	MINI	36.50	3	3	5	1.20	60- 90	(65-145%)	17.9	3.0	2.04	1.10	7	6/30	.41	.35	9/30	.275	.25	YES
1239	840	Moderna, Inc.	(NDQ)	MRNA	14.81	–	4	–	NMF	14- 25	(N- 70%)	NMF	NIL	d1.80	NIL	71	6/30	d.41	NA	9/30	NIL	NIL	YES
	995	Modine Mfg.		MOD	10.89	4	4	3	1.35	20- 35	(85-220%)	8.1	NIL	1.35	NIL	82	6/30	.31	.41	9/30	NIL	NIL	YES
2666	1156	Mohawk Inds.		MHK	121.27	4	3	3	1.20	230- 345	(90-185%)	11.9	NIL	10.17	NIL	51	6/30	2.89	3.51	9/30	NIL	NIL	YES
	809	Molina Healthcare		MOH	109.48	4	3	1	1.20	195- 290	(80-165%)	9.4	NIL	11.61	NIL	40	6/30	3.06	3.02	9/30	NIL	NIL	YES
	1977	Molson Coors Brewing		TAP	58.11	4	3	5	.90	80- 115	(40-100%)	12.3	3.9	4.72	2.28	30	6/30	1.52	1.96	9/30	▲.57	.41	YES
	2365	Monarch Casino	(NDQ)	MCRI	41.59	2	3	1	1.10	55- 80	(30- 90%)	19.6	NIL	2.12	NIL	56	6/30	.50	.50	9/30	NIL	NIL	YES
	1930	Mondelez Int'l	(NDQ)	MDLZ	54.64	3	2	3	.95	60- 80	(10- 45%)	21.5	2.1	2.54	1.14	46	6/30	.57	.56	12/31	▲.285	.26	YES
	1370	Monolithic Power Sys.	(NDQ)	MPWR	153.35	3	3	2	1.25	170- 255	(10- 65%)	60.9	1.0	2.52	1.60	73	6/30	.45	.55	12/31	.40	.30	YES
	2128	Monro, Inc.	(NDQ)	MNRO	78.47	2	3	3	.85	70- 105	(N- 35%)	29.6	1.1	2.65	.88	4	6/30	.67	.62	9/30	.22	.20	YES
	1978	Monster Beverage	(NDQ)	MNST	56.42	2	3	2	.80	80- 115	(40-105%)	27.5	NIL	2.05	NIL	30	6/30	.53	.48	9/30	NIL	NIL	YES
	442	Moody's Corp.		MCO	201.49	3	3	1	1.15	205- 310	(N- 55%)	24.8	1.0	8.13	2.00	11	6/30	2.07	2.04	9/30	.50	.44	YES
	717	Moog Inc. 'A'		MOGA	80.66	3	3	3	1.25	80- 120	(N- 50%)	16.5	1.2	4.88	1.00	44	6/30	1.36	1.12	9/30	.25	.25	YES
	1814	Morgan Stanley		MS	41.38	3	3	3	1.35	85- 130	(105-215%)	7.9	3.4	5.21	1.40	48	6/30	1.23	1.30	9/30	▲.35	.30	YES
	1607	Mosaic Company		MOS	20.21	4	3	4	1.45	35- 55	(75-170%)	14.3	1.1	1.41	.23	76	6/30	.13	.18	9/30	.05	.025	YES
	996	Motorcar Parts Of Amer.	(NDQ)	MPAA	15.99	4	3	3	1.30	30- 45	(90-180%)	8.6	NIL	1.85	NIL	82	6/30	.09	.15	9/30	NIL	NIL	YES
	957	Motorola Solutions		MSI	165.44	1	2	2	.95	170- 230	(5- 40%)	20.8	1.5	7.97	2.46	28	6/30	1.69	1.46	12/31	.57	.52	YES
	2180	Movado Group		MOV	24.53	5	3	4	1.20	60- 90	(145-265%)	8.4	3.3	2.91	.80	91	7/31	.36	.45	9/30	.20	.20	YES
	732	Mueller Inds.		MLI	27.70	▼4	3	3	1.30	45- 65	(60-135%)	14.8	1.4	1.87	.40	67	6/30	.50	.58	9/30	.10	.10	YES
	1724	Mueller Water Prod.		MWA	10.84	3	3	4	1.20	18- 30	(65-175%)	16.2	1.8	.67	.20	23	6/30	.21	.10	9/30	.05	.05	YES
	513	Murphy Oil Corp.		MUR	21.68	3	3	4	1.70	60- 90	(175-315%)	9.0	4.6	2.42	1.00	53	6/30	.54	.26	9/30	.25	.25	YES
	2181	Murphy USA Inc.		MUSA	85.37	3	3	2	.85	95- 145	(10- 70%)	18.4	NIL	4.64	NIL	91	6/30	1.01	1.58	9/30	NIL	NIL	YES
	1769	Myers Inds.		MYE	17.45	4	3	3	1.20	25- 35	(45-100%)	23.0	3.1	.76	.54	45	6/30	.18	.26	12/31	.135	.135	YES
2667	1633	Mylan N.V.	(NDQ)	MYL	18.83	–	3	–	1.30	25- 35	(35- 85%)	94.2	NIL	.20	NIL	68	6/30	d.33	.07	9/30	NIL	NIL	YES
452	841	Myriad Genetics	(NDQ)	MYGN	28.29	3	3	5	.90	45- 70	(60-145%)	15.6	NIL	1.81	NIL	71	6/30	.41	.38	9/30	NIL	NIL	YES
	1338	NCR Corp.		NCR	30.34	3	3	2	1.55	45- 70	(50-130%)	10.6	NIL	2.87	NIL	74	6/30	.76	.65	9/30	NIL	NIL	YES
	768	NMI Holdings	(NDQ)	NMIH	26.56	2	3	2	1.10	35- 50	(30- 90%)	11.1	NIL	2.39	NIL	2	6/30	.56	.37	9/30	NIL	NIL	YES
	733	NN Inc.	(NDQ)	NNBR	7.03	3	4	4	1.65	6- 10	(N- 40%)	NMF	4.0	d.54	.28	67	6/30	d.16	d.89	9/30	.07	.07	YES
	1216	NRG Energy		NRG	39.14	3	3	4	1.30	40- 60	(N- 55%)	11.6	0.3	3.38	.12	27	6/30	.75	.23	9/30	.03	.03	YES
	1131	NVR, Inc.		NVR	3718.71	2	2	2	.85	3060-4140	(N- 10%)	16.4	NIL	227.36	NIL	24	6/30	53.09	49.05	9/30	NIL	NIL	
	1372	NXP Semiconductors NV	(NDQ)	NXPI	108.97	3	3	2	1.25	175- 260	(60-140%)	13.8	1.4	7.89	1.50	73	6/30	1.81	1.50	12/31	▲.375	.25	YES
	2427	Nabors Inds.		NBR	1.70	5	5	3	2.15	5- 9	(195-430%)	NMF	2.4	d.59	.04	96	6/30	d.41	d.39	12/31	.01	.06	YES
	1807	Nasdaq, Inc.	(NDQ)	NDAQ	98.59	2	2	3	.90	95- 130	(N- 30%)	18.5	1.9	5.33	1.88	21	6/30	1.22	1.18	9/30	.47	.44	YES
	2521	Nat'l Bank of Canada	(TSE)	NA.TO	65.95b	2	2	4	.85	80- 110	(20- 65%)	10.5	4.3	6.26	2.84	37	7/31	1.66(b)	1.52(b)	12/31	.68(b)	.62(b)	YES
	1979	National Beverage	(NDQ)	FIZZ	46.06	5	3	5	.80	75- 115	(65-150%)	16.9	NIL	2.73	NIL	30	7/31	.74	1.04	9/30	NIL	NIL	YES
	2395	National CineMedia	(NDQ)	NCMI	8.19	4	3	4	.85	13- 20	(60-145%)	21.0	8.3	.39	.68-.34	69	6/30	.11	.05	9/30	.17	.17	YES
	540	National Fuel Gas		NFG	45.59	3	3	4	.95	100- 150	(120-230%)	13.4	3.8	3.41	1.74	92	6/30	.71	.73	12/31	.435	.425	YES
2667	127	National Instruments	(NDQ)	NATI	41.20	3	3	3	1.05	40- 60	(N- 45%)	33.2	2.4	1.24	1.00	35	6/30	.22	.23	9/30	.25	.23	YES
	2428	National Oilwell Varco		NOV	20.86	4	3	4	1.30	40- 60	(90-190%)	NMF	1.0	.11	.20	96	6/30	d.04	.06	9/30	.05	.05	YES
	1770	National Presto Ind.		NPK	87.89	4	3	4	.90	95- 145	(10- 65%)	14.0	6.8	6.30	6.00	45	3/31	.85	1.57	9/30	NIL	NIL	
	2182	National Vision Holdings	(NDQ)	EYE	25.05	–	3	–	NMF	40- 60	(60-140%)	42.5	NIL	.59	NIL	91	6/30	.13	.16	9/30	NIL	NIL	YES
	1592	Natural Resource		NRP	25.76	▼4	4	3	1.45	35- 55	(35-115%)	5.4	7.0	4.80	1.80	89	6/30	.85	1.75	9/30	.45	.45	YES
	218	Natus Medical	(NDQ)	NTUS	30.78	4	3	4	.90	40- 60	(30- 95%)	31.1	NIL	.99	NIL	31	6/30	.12	d.08	9/30	NIL	NIL	YES
	2183	Nautilus Inc.		NLS					SEE FINAL REPORT														
	2573	Navient Corp.	(NDQ)	NAVI	12.02	3	3	2	1.40	17- 25	(40-110%)	6.0	5.3	2.02	.64	13	6/30	.64	.31	9/30	.16	.16	YES
236	399	Navigant Consulting		NCI	27.95	–	3	–	1.00	17- 25	(N- N%)	38.8	0.7	.72	.20	7	6/30	.22	.17	9/30	.05	.05	YES
	161	Navistar Int'l		NAV	26.78	4	5	3	1.95	45- 85	(70-215%)	7.0	NIL	3.83	NIL	59	7/31	1.47	1.71	9/30	NIL	NIL	YES
	1164	Neenah, Inc.		NP	61.76	4	3	3	1.00	80- 120	(30- 95%)	17.3	2.9	3.56	1.80	87	6/30	.80	1.18	9/30	.45	.41	YES
452	1634	Nektar Therapeutics	(NDQ)	NKTR	18.43	5	5	4	1.25	30- 50	(65-170%)	NMF	NIL	d2.70	NIL	68	6/30	d.63	5.33	9/30	NIL	NIL	YES
1661	219	Neogen Corp.	(NDQ)	NEOG	64.61	3	3	2	1.00	65- 100	(N- 55%)	52.5	NIL	1.23	NIL	31	8/31	.28	.29	12/31	NIL	NIL	YES
	1931	Nestle SA ADS	(PNK)	NSRGY	107.16	3	1	2	.70	105- 130	(N- 20%)	30.6	2.3	3.50	2.45	46	6/30	1.68(p)	1.92(p)	9/30	NIL	NIL	
236	1407	NetApp, Inc.	(NDQ)	NTAP	51.99	4	3	4	1.20	70- 105	(35-100%)	15.1	3.7	3.45	1.92	77	7/31	.42	1.05	12/31	.48	.40	YES
2234	2338	Netflix, Inc.	(NDQ)	NFLX	269.58	4	3	3	1.20	320- 480	(20- 80%)	74.3	NIL	3.63	NIL	72	6/30	.60	.85	9/30	NIL	NIL	YES
	958	NETGEAR	(NDQ)	NTGR	32.33	–	3	–	NMF	45- 70	(40-115%)	15.0	NIL	2.15	NIL	28	6/30	.28	.29	9/30	NIL	NIL	YES
	185	Nevro Corp.		NVRO	83.14	3	4	2	1.05	70- 115	(N- 40%)	NMF	NIL	d2.75	NIL	16	6/30	d.91	d.35	9/30	NIL	NIL	YES
	428	New Germany Fund		GF	13.72	–	3	–	.90	16- 25	(15- 80%)	NMF	1.5	NMF	.20	–	6/30	16.19(q)	20.51(q)	9/30	NIL	NIL	
	550	New Jersey Resources		NJR	44.51	3	1	2	.70	40- 45	(N- N%)	21.9	2.8	2.03	1.25	52	6/30	d.20	d.09	12/31	▲.313	.293	YES
232	2384	New Media Investment		NEWM	8.58	–	3	–	1.00	12- 17	(40-100%)	14.3	17.7	.60	1.52-.70	–	6/30	.05	.20	9/30	.38	.37	YES
	2002	New Orient. Ed. ADS		EDU	111.22	2	3	2	1.10	110- 165	(N- 50%)	37.7	NIL	2.95	NIL	10	5/31	.60	.55	9/30	NIL	NIL	YES
1422	1831	New Relic, Inc.		NEWR	61.64	5	3	5	.95	85- 130	(40-110%)	NMF	NIL	▼d.70	NIL	54	6/30	d.26	d.10	9/30	NIL	NIL	YES
	1505	New York Community		NYCB	12.50	3	3	3	.95	15- 20	(20- 60%)	15.8	5.4	.79	.68	8	6/30	.19	.20	9/30	.17	.17	YES
	2385	New York Times		NYT	28.33	2	3	2	1.05	30- 45	(5- 60%)	30.8	0.7	.92	.20	–	6/30	.15	.14	12/31	.05	.04	YES
236	1191	Newell Brands	(NDQ)	NWL	18.62	4	3	5	1.15	50- 75	(170-305%)	11.2	4.9	1.66	.92	39	6/30	.21	.24	9/30	.23	.23	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
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PAGE NUMBERS		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 3-31-20	(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?
	582	NewMarket Corp.		NEU	469.12	3	2	2	.95	410- 550	(N- 15%)	20.6	1.6	22.73	7.60	62	6/30	6.63	4.53	12/31	▲1.90	1.75	YES
	1576	Newmont Goldcorp		NEM	37.56	3	3	2	.75	30- 45	(N- 20%)	26.5	1.5	1.42	.56	15	6/30	.12	.27	9/30	.14	.14	YES
	2386	News Corp. 'A'	(NDQ)	NWSA	13.88	3	3	3	1.25	25- 40	(80-190%)	25.2	1.4	.55	.20	–	6/30	d.09	d.64	12/31	.10	.10	YES
	2339	Nexstar Media Group	(NDQ)	NXST	101.82	3	3	3	1.35	150- 225	(45-120%)	13.8	1.8	7.40	1.80	72	6/30	1.42	1.86	9/30	.45	.375	YES
	143	NextEra Energy		NEE	232.03	1	1	3	.55	185- 225	(N- N%)	26.7	2.3	8.69	5.33	14	6/30	2.56	1.64	9/30	1.25	1.11	YES
	824	NextGen Healthcare	(NDQ)	NXGN	15.24	4	3	4	.70	25- 35	(65-130%)	17.9	NIL	.85	NIL	70	6/30	.16	.19	9/30	NIL	NIL	YES
	443	Nielsen Hldgs. plc		NLSN	20.97	4	3	4	.95	30- 45	(45-115%)	22.5	6.7	.93	1.40	11	6/30	.34	.20	9/30	.35	.35	YES
1662	2160	NIKE, Inc. 'B'		NKE	92.28	2	1	3	1.00	95- 115	(5- 25%)	34.3	1.0	2.69	.88	38	8/31	.86	.67	9/30	.22	.20	YES
	551	NiSource Inc.		NI	29.73	3	3	3	.55	25- 35	(N- 20%)	22.4	2.7	1.33	.80	52	6/30	.05	.07	12/31	.20	.195	YES
	108	Nissan Motor ADR(g)	(PNK)	NSANY	12.77	4	3	4	.95	20- 30	(55-135%)	9.1	8.6	1.40	1.10	58	6/30	.03	.53	9/30	.529	.48	
640	2429	Noble Corp. plc		NE	1.19	–	5	–	2.10	7- 13	(490-990%)	NMF	NIL	d1.71	NIL	96	6/30	d.34	d.49	9/30	NIL	NIL	YES
	2411	Noble Energy		NBL	21.40	4	3	4	1.70	30- 50	(40-135%)	85.6	2.2	.25	.48	95	6/30	d.02	d.05	9/30	.12	.11	YES
	959	Nokia Corp. ADR		NOK	4.91	2	3	3	.90	8- 12	(65-145%)	14.9	4.5	.33	.22	28	6/30	.05	.03	9/30	.056	NIL	YES
	1725	Nordson Corp.	(NDQ)	NDSN	141.93	3	3	3	1.20	▼ 135- 205	(N- 45%)	23.5	1.1	6.04	1.55	23	7/31	1.62	1.60	9/30	▲.38	.35	YES
642	2146	Nordstrom, Inc.		JWN	33.48	5	3	4	1.00	55- 85	(65-155%)	9.9	4.4	3.37	1.48	57	7/31	.90	.95	9/30	.37	.37	YES
	346	Norfolk Southern		NSC	174.98	2	2	3	1.15	225- 305	(30- 75%)	16.1	2.1	10.84	3.76	25	6/30	2.70	2.50	9/30	▲.94	.80	YES
	784	Northern Trust Corp.	(NDQ)	NTRS	89.88	3	3	3	1.20	115- 170	(30- 90%)	13.1	3.1	6.87	2.80	47	6/30	1.75	1.68	12/31	▲.70	.55	YES
	1217	Northland Power	(TSE)	NPI.TO	25.36b	2	3	2	.65	35- 55	(40-115%)	14.5	4.7	1.75	1.20	27	6/30	.28(b)	.29(b)	9/30	.30(b)	.30(b)	YES
	718	Northrop Grumman		NOC	367.79	2	1	2	.85	390- 475	(5- 30%)	18.9	1.4	19.44	5.28	44	6/30	5.06	4.52	9/30	1.32	1.20	YES
	1506	Northwest Bancshares	(NDQ)	NWBI	16.18	2	2	4	.80	19- 25	(15- 55%)	15.4	4.6	1.05	.75	8	6/30	.25	.25	9/30	.18	.17	YES
	552	Northwest Natural		NWN	70.60	3	1	2	.60	70- 85	(N- 20%)	28.8	2.7	2.45	1.90	52	6/30	.07	d.01	9/30	.475	.473	YES
	2225	NorthWestern Corp.		NWE	74.76	3	2	3	.60	60- 80	(N- 5%)	21.3	3.1	3.51	2.35	50	6/30	.49	.61	9/30	.575	.55	YES
	2315	Norwegian Cruise Line		NCLH	50.76	2	3	4	1.20	105- 160	(105-215%)	9.3	NIL	5.46	NIL	36	6/30	1.30	1.01	9/30	NIL	NIL	YES
	1635	Novartis AG ADR		NVS	86.04	3	1	2	.90	110- 135	(30- 55%)	23.6	3.3	3.64	2.87	68	6/30	.91	3.34	9/30	NIL	NIL	YES
	1636	Novo Nordisk ADR(g)		NVO	50.55	3	2	2	.95	65- 85	(30- 70%)	19.9	2.6	2.54	1.30	68	6/30	.59	.65	9/30	.445	.462	YES
	220	NovoCure Limited	(NDQ)	NVCR	73.62	2	4	1	1.30	80- 135	(10- 85%)	NMF	NIL	d.06	NIL	31	6/30	d.01	d.17	9/30	NIL	NIL	YES
2234	1012	Nu Skin Enterprises		NUS	42.40	5	3	4	1.10	70- 105	(65-150%)	12.7	3.5	3.33	1.50	78	6/30	.83	.90	9/30	.37	.365	YES
	2600	Nuance Communic.	(NDQ)	NUAN	16.45	–	3	–	1.10	25- 35	(50-115%)	NMF	NIL	.03	NIL	19	6/30	.04	d.05	9/30	NIL	NIL	YES
	744	Nucor Corp.		NUE	50.41	3	3	4	1.30	120- 180	(140-255%)	9.1	3.2	5.57	1.60	93	6/30	1.26	2.13	12/31	.40	.40	YES
	632	NuStar Energy L.P.		NS	28.11	3	3	2	1.50	25- 35	(N- 25%)	40.7	8.5	.69	2.40	18	6/30	.18	.15	9/30	.60	.60	YES
	1832	Nutanix, Inc.	(NDQ)	NTNX	25.35	–	4	–	1.90	55- 95	(115-275%)	NMF	NIL	▼d2.79	NIL	54	7/31	d1.04	d.51	9/30	NIL	NIL	YES
	1608	Nutrien Ltd.		NTR	50.14	–	3	–	NMF	70- 105	(40-110%)	16.3	3.6	3.07	1.80	76	6/30	1.50	1.21	9/30	.43	.40	YES
	186	NuVasive, Inc.	(NDQ)	NUVA	60.96	2	3	3	.90	80- 120	(30- 95%)	57.0	NIL	1.07	NIL	16	6/30	.29	.22	9/30	NIL	NIL	YES
	1204	Nuveen Muni Value Fund		NUV	10.49	–	1	–	.40	9- 11	(N- 5%)	NMF	3.8	NMF	.40	–	4/30	10.29(q)	10.01(q)	9/30	.093	.093	
	1312	nVent Electric plc		NVT	20.11	–	3	–	NMF	25- 35	(25- 75%)	13.1	3.5	1.53	.71	66	6/30	.35	.24	12/31	.175	.175	YES
	1371	NVIDIA Corp.	(NDQ)	NVDA	174.00	4	3	3	1.35	165- 250	(N- 45%)	32.8	0.4	5.31	.64	73	7/31	.90	1.76	9/30	.16	.15	YES
	913	OGE Energy		OGE	45.26	3	2	3	.80	40- 55	(N- 20%)	21.5	3.5	2.11	1.58	42	6/30	.50	.55	12/31	▲.388	.365	YES
	128	OSI Systems	(NDQ)	OSIS	99.29	1	3	2	.90	100- 155	(N- 55%)	27.4	NIL	3.62	NIL	35	6/30	.89	.27	9/30	NIL	NIL	YES
237	2412	Oasis Petroleum		OAS	3.37	5	5	3	2.30	14- 25	(315-640%)	15.3	NIL	.22	NIL	95	6/30	.03	.10	9/30	NIL	NIL	YES
	514	Occidental Petroleum		OXY	43.77	4	3	3	1.20	80- 120	(85-175%)	7.6	7.2	5.76	3.17	53	6/30	.97	1.10	12/31	▲.79	.78	YES
	2430	Oceaneering Int'l		OII	13.08	4	3	3	1.60	25- 40	(90-205%)	NMF	NIL	d.70	NIL	96	6/30	d.36	d.34	9/30	NIL	NIL	YES
	1418	Office Depot	(NDQ)	ODP	1.71	5	5	3	1.30	4- 7	(135-310%)	4.8	5.8	.36	.10	86	6/30	.07	.05	9/30	.025	.025	YES
2673	2431	Oil States Int'l		OIS	13.20	5	3	3	1.60	35- 50	(165-280%)	NMF	NIL	.09	NIL	96	6/30	d.14	.05	9/30	NIL	NIL	YES
	2601	Okta, Inc.	(NDQ)	OKTA	103.69	–	3	–	NMF	90- 135	(N- 30%)	NMF	NIL	d.46	NIL	19	7/31	d.05	d.15	9/30	NIL	NIL	YES
	325	Old Dominion Freight	(NDQ)	ODFL	165.52	2	2	2	1.15	150- 200	(N- 20%)	20.7	0.4	8.01	.70	63	6/30	2.16	1.99	9/30	.17	.13	YES
	785	Old Nat'l Bancorp	(NDQ)	ONB	17.03	3	3	3	1.05	18- 30	(5- 75%)	11.9	3.1	1.43	.52	47	6/30	.36	.29	9/30	.13	.13	YES
	769	Old Republic		ORI	23.32	3	3	3	.95	40- 60	(70-155%)	12.5	3.4	1.87	.80	2	6/30	.45	.47	9/30	.20	.195	YES
	1609	Olin Corp.		OLN	17.92	4	3	5	1.45	30- 45	(65-150%)	15.3	4.5	1.17	.80	76	6/30	NIL	.39	9/30	.20	.20	YES
	2147	Ollie's Bargain Outlet	(NDQ)	OLLI	58.40	4	3	3	1.25	95- 140	(65-140%)	26.3	NIL	2.22	NIL	57	7/31	.35	.40	9/30	NIL	NIL	YES
	221	Omnicell, Inc.	(NDQ)	OMCL	72.22	3	3	2	1.00	100- 150	(40-110%)	25.4	NIL	2.84	NIL	31	6/30	.67	.46	9/30	NIL	NIL	YES
	2396	Omnicom Group		OMC	78.13	3	2	2	.90	115- 155	(45-100%)	12.9	3.5	6.08	2.70	69	6/30	1.68	1.60	12/31	.65	.60	YES
237	1373	ON Semiconductor	(NDQ)	ON	18.76	4	3	4	1.50	30- 40	(60-115%)	12.8	NIL	1.47	NIL	73	6/30	.42	.46	9/30	NIL	NIL	YES
	553	ONE Gas, Inc.		OGS	95.23	3	2	3	.65	100- 135	(5- 40%)	27.1	2.2	3.51	2.12	52	6/30	.46	.39	9/30	.50	.46	YES
641	2652	1-800-FLOWERS.COM	(NDQ)	FLWS	14.41	3	4	2	1.20	15- 25	(5- 75%)	24.8	NIL	.58	NIL	55	6/30	d.13	d.13	9/30	NIL	NIL	YES
	615	ONEOK Inc.		OKE	72.71	3	3	3	1.55	85- 125	(15- 70%)	22.1	5.2	3.29	3.75	29	6/30	.75	.68	9/30	▲.89	.825	YES
	928	Ooma, Inc.		OOMA	10.72	4	4	3	1.05	12- 18	(10- 70%)	NMF	NIL	d.84	NIL	43	7/31	d.24	d.20	9/30	NIL	NIL	YES
	1833	Open Text Corp.	(NDQ)	OTEX	40.38	3	3	2	.90	45- 65	(10- 60%)	35.1	1.7	1.15	.70	54	6/30	.27	.23	9/30	.175	.152	YES
	1637	Opko Health	(NDQ)	OPK	2.00	5	5	3	1.55	6- 9	(200-350%)	NMF	NIL	d.41	NIL	68	6/30	d.10	d.01	9/30	NIL	NIL	YES
	2602	Oracle Corp.		ORCL	53.80	3	1	2	1.05	70- 90	(30- 65%)	14.0	1.8	3.85	.96	19	8/31	.81	.71	12/31	.24	.19	YES
	2129	O'Reilly Automotive	(NDQ)	ORLY	400.67	2	3	3	.90	390- 585	(N- 45%)	22.3	NIL	17.94	NIL	4	6/30	4.51	4.28	9/30	NIL	NIL	YES
	1218	Ormat Technologies		ORA	73.72	2	3	2	.85	65- 100	(N- 35%)	33.7	0.7	2.19	.50	27	6/30	.66	d.01	9/30	.11	.10	YES
	162	Oshkosh Corp.		OSK	72.81	3	3	3	1.25	105- 155	(45-115%)	9.3	1.5	7.87	1.08	59	6/30	2.72	2.20	9/30	.27	.24	YES
	914	Otter Tail Corp.	(NDQ)	OTTR	53.35	3	2	3	.65	40- 55	(N- 5%)	24.6	2.7	2.17	1.45	42	6/30	.39	.47	9/30	.35	.335	YES
	222	Owens & Minor		OMI						SEE FINAL REPORT													
	1116	Owens Corning		OC	61.64	3	3	4	1.15	70- 110	(15- 80%)	12.3	1.4	5.00	.88	49	6/30	1.26	1.08	12/31	.22	.22	YES
	1177	Owens-Illinois		OI	9.70	3	3	3	1.35	35- 50	(260-415%)	3.7	2.1	2.59	.20	41	6/30	.69	.77	9/30	.05	NIL	YES
	2111	Oxford Inds.		OXM	70.85	4	3	3	1.15	90- 135	(25- 90%)	15.2	2.2	4.65	1.54	80	7/31	1.84	1.83	12/31	.37	.34	YES
	515	PBF Energy		PBF	27.33	5	3	5	1.45	70- 110	(155-300%)	11.6	4.4	2.36	1.20	53	6/30	d.27	2.37	9/30	.30	.30	YES
	2184	PC Connection	(NDQ)	CNXN	38.31	3	3	3	1.05	35- 55	(N- 45%)	15.0	NIL	2.55	NIL	91	6/30	.89	.68	9/30	NIL	NIL	YES
848	541	PDC Energy	(NDQ)	PDCE	26.74	3	4	4	1.75	50- 80	(85-200%)	7.0	NIL	3.82	NIL	92	6/30	1.04	d2.43	9/30	NIL	NIL	YES
849	1638	PDL BioPharma	(NDQ)	PDLI	2.13	–	4	–	1.15	4- 6	(90-180%)	14.2	NIL	.15	NIL	68	6/30	d.04	d.76	9/30	NIL	NIL	YES
	2522	PNC Financial Serv.		PNC	137.20	3	2	3	1.05	160- 215	(15- 55%)	11.9	3.4	11.49	4.60	37	6/30	2.88	2.72	9/30	▲1.15	.95	YES
	2226	PNM Resources		PNM	52.56	3	3	3	.60	35- 55	(N- 5%)	24.9	2.3	2.11	1.21	50	6/30	.35	.48	12/31	.29	.265	YES
	2447	PPG Inds.		PPG	116.87	3	1	3	1.10	125- 185	(5- 60%)	19.3	1.7	6.04	2.04	83	6/30	1.14	1.51	9/30	▲.51	.48	YES
	144	PPL Corp.		PPL	31.31	3	2	5	.65	35- 45	(10- 45%)	12.7	5.3	2.46	1.66	14	6/30	.60	.73	12/31	.413	.41	YES
	583	PQ Group Holdings		PQG	15.68	–	3	–	1.15	20- 30	(30- 90%)	16.9	NIL	.93	NIL	62	6/30	.23	.11	9/30	NIL	NIL	YES
	810	PRA Health Sciences	(NDQ)	PRAH	96.16	3	3	2	1.15	110- 170	(15- 75%)	18.5	NIL	5.20	NIL	40	6/30	1.22	1.00	9/30	NIL	NIL	YES
	2603	PTC Inc.	(NDQ)	PTC	66.04	4	3	3	1.10	65- 95	(N- 45%)	60.6	NIL	1.09	NIL	19	6/30	d.10	.14	9/30	NIL	NIL	YES
	2112	PVH Corp.		PVH	85.66	4	3	4	1.20	170- 250	(100-190%)	8.1	0.2	10.59	.15	80	7/31	2.10	2.18	9/30	.038	.037	YES
	163	PACCAR Inc.	(NDQ)	PCAR	67.54	2	2	3	1.15	95- 125	(40- 85%)	10.1	4.9	6.69	3.30	59	6/30	1.78	1.59	12/31	.32	.28	YES
	1178	Packaging Corp.		PKG	102.79	3	3	3	1.20	130- 195	(25- 90%)	13.8	3.1	7.43	3.16	41	6/30	2.04	1.97	12/31	.79	.79	YES
	2604	Palo Alto Networks		PANW	205.00	3	3	3	1.10	270- 410	(30-100%)	NMF	NIL	d.30	NIL	19	7/31	d.22	d.02	9/30	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 3-31-20, 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.

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Page Numbers	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 3-31-20	(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?
1935	Sanderson Farms (NDQ)	SAFM	148.72	2	3	3	.70	135- 200	(N- 35%)	17.6	0.9	8.44	1.28	46	7/31	2.41	.50	12/31	.32	.32	YES
1343	Sanmina Corp. (NDQ)	SANM	31.50	2	3	3	1.25	45- 65	(45-105%)	9.4	NIL	3.36	NIL	74	6/30	.82	.55	9/30	NIL	NIL	YES
1642	Sanofi ADR (NDQ)	SNY	45.18	3	1	3	.90	50- 60	(10- 35%)	27.5	4.0	1.64	1.80	68	6/30	d.04	.36	9/30	NIL	NIL	YES
2578	Santander Consumer USA	SC	25.53	3	3	2	1.10	30- 50	(20- 95%)	8.7	3.4	2.94	.88	13	6/30	1.05	.93	9/30	.22	.20	YES
1936	Saputo Inc. (TSE)	SAP.TO	40.40b	2	1	5	.55	40- 50	(N- 25%)	19.4	1.7	2.08	.68	46	6/30	.42(b)	.41(b)	9/30	▲.17(b)	.165(b)	YES
1409	ScanSource (NDQ)	SCSC	29.80	4	3	3	1.20	45- 65	(50-120%)	10.1	NIL	2.95	NIL	77	6/30	.71	.77	12/31	NIL	NIL	YES
225	Schein (Henry) (NDQ)	HSIC	63.05	–	3	–	NMF	85- 125	(35-100%)	18.2	NIL	3.47	NIL	31	6/30	.77	.92	9/30	NIL	NIL	YES
2435	Schlumberger Ltd.	SLB	32.70	4	3	3	1.30	75- 110	(130-235%)	20.4	6.1	1.60	2.00	96	6/30	.35	.31	12/31	.50	.50	YES
1663 748	Schnitzer Steel (NDQ)	SCHN	20.38	4	3	3	1.45	55- 80	(170-295%)	7.8	3.7	2.62	.75	93	5/31	.56	1.31	9/30	.188	.188	YES
2379	Scholastic Corp. (NDQ)	SCHL	37.56	3	3	5	.90	35- 55	(N- 45%)	32.9	1.6	1.14	.60	90	8/31	d1.68	d1.74	12/31	.15	.15	YES
1808	Schwab (Charles) (NDQ)	SCHW	37.76	3	3	4	1.25	60- 85	(60-125%)	14.8	2.0	2.56	.75	21	6/30	.66	.60	9/30	.17	.13	YES
1993	Schweitzer-Mauduit Int'l	SWM	36.51	4	3	4	.85	40- 60	(10- 65%)	12.0	4.8	3.04	1.76	84	6/30	.66	.83	9/30	.44	.43	YES
1239 403	Science Applications	SAIC	85.17	2	3	3	1.00	115- 175	(35-105%)	15.0	1.7	5.69	1.48	7	7/31	1.35	1.13	12/31	.37	.31	YES
2368	Scientific Games (NDQ)	SGMS	19.48	3	5	4	2.10	45- 85	(130-335%)	34.2	NIL	.57	NIL	56	6/30	d.83	d.06	9/30	NIL	NIL	YES
1193	Scotts Miracle-Gro	SMG	100.82	1	3	1	1.00	80- 120	(N- 20%)	20.4	2.3	4.94	2.32	39	6/30	3.15	2.23	9/30	▲.58	.55	YES
453 2341	Scripps (E.W.) 'A' (NDQ)	SSP	12.97	5	3	4	1.20	35- 50	(170-285%)	13.2	1.5	.98	.20	72	6/30	d.01	.10	9/30	.05	.05	YES
1410	Seagate Technology (NDQ)	STX	52.86	3	3	3	1.35	45- 70	(N- 30%)	12.9	4.8	4.11	2.52	77	6/30	.86	1.62	12/31	.63	.63	YES
1179	Sealed Air	SEE	40.79	3	3	2	1.00	60- 90	(45-120%)	21.6	1.6	1.89	.64	41	6/30	.16	.52	9/30	.16	.16	YES
★★ 844	Seattle Genetics (NDQ)	SGEN	86.00	4	4	3	1.35	90- 150	(5- 75%)	NMF	NIL	d1.62	NIL	71	6/30	d.49	.47	9/30	NIL	NIL	YES
2320	SeaWorld Entertainment	SEAS	25.86	2	3	2	1.00	30- 50	(15- 95%)	18.6	NIL	1.39	NIL	36	6/30	.64	.26	9/30	NIL	NIL	YES
812	Select Med. Hldgs.	SEM	16.24	▲3	3	3	1.25	18- 25	(10- 55%)	14.8	NIL	1.10	NIL	40	6/30	.33	.35	9/30	NIL	NIL	YES
772	Selective Ins. Group (NDQ)	SIGI	74.38	2	3	1	.90	55- 80	(N- 10%)	16.9	1.1	4.40	.80	2	6/30	1.16	1.01	9/30	.20	.18	YES
2229	Sempra Energy	SRE	146.08	3	2	3	.75	130- 180	(N- 25%)	23.9	2.8	6.12	4.04	50	6/30	1.10	1.27	12/31	.968	.895	YES
1377	Semtech Corp. (NDQ)	SMTC	47.34	4	3	3	1.35	55- 85	(15- 80%)	29.4	NIL	1.61	NIL	73	7/31	.38	.55	9/30	NIL	NIL	YES
130	Sensata Techn. plc	ST	49.67	3	3	4	1.25	75- 110	(50-120%)	13.0	NIL	3.82	NIL	35	6/30	.93	.93	9/30	NIL	NIL	YES
1937	Sensient Techn.	SXT	68.09	3	2	4	1.10	70- 90	(5- 30%)	20.3	2.1	3.36	1.45	46	6/30	.81	.92	9/30	.36	.33	YES
1848	Service Corp. Int'l	SCI	47.35	3	3	2	1.05	50- 75	(5- 60%)	23.9	1.5	1.98	.72	85	6/30	.47	.44	9/30	.18	.17	YES
1546	Service Properties (NDQ)	SVC	25.38	3	3	4	1.05	35- 50	(40- 95%)	28.8	8.6	.88	2.18	33	6/30	.05	.59	9/30	.54	.53	YES
238 404	ServiceMaster Global	SERV	54.90	–	3	–	NMF	40- 60	(N- 10%)	48.2	NIL	1.14	NIL	7	6/30	.43	.29	9/30	NIL	NIL	YES
2634	ServiceNow, Inc.	NOW	250.13	2	3	2	1.20	180- 270	(N- 10%)	NMF	NIL	.15	NIL	1	6/30	d.06	d.30	9/30	NIL	NIL	YES
370	Shake Shack	SHAK	93.62	3	4	2	1.30	60- 95	(N- N%)	NMF	NIL	.83	NIL	32	6/30	.29	.29	9/30	NIL	NIL	YES
1025	Shaw Commun. 'B' (TSE)	SJRB.TO	25.98b	2	2	5	.60	30- 40	(15- 55%)	16.8	4.6	1.55	1.20	17	5/31	.44(b)	d.18(b)	9/30	.296(b)	.296(b)	YES
636	Shell Midstream L.P.	SHLX	20.30	3	3	3	1.20	35- 55	(70-170%)	12.5	9.4	1.63	1.90	18	6/30	.38	.35	9/30	▲.43	.365	YES
929	Shenandoah Telecom. (NDQ)	SHEN	30.82	3	3	3	.95	45- 70	(45-125%)	24.3	1.0	1.27	.30	43	6/30	.26	.19	9/30	NIL	NIL	YES
1142	Sherwin-Williams	SHW	544.86	1	2	3	1.10	525- 710	(N- 30%)	25.2	0.9	21.65	5.03	9	6/30	6.57	5.73	9/30	1.13	.86	YES
336	Ship Finance Int'l	SFL	14.00	2	3	3	1.20	13- 20	(N- 45%)	14.1	10.0	.99	1.40-.80	61	6/30	.26	.15	9/30	.35	.35	YES
1837	Shopify Inc.	SHOP	313.22	2	4	1	1.50	280- 470	(N- 50%)	NMF	NIL	▼.66	NIL	54	6/30	.14	.02	9/30	NIL	NIL	YES
1778	Siemens AG (ADS) (PNK)	SIEGY	52.74	3	2	4	1.05	90- 125	(70-135%)	12.3	4.1	4.30	2.17	45	6/30	.70	.74	9/30	NIL	NIL	
604	Sierra Wireless (NDQ)	SWIR	10.36	5	4	3	1.50	25- 40	(140-285%)	NMF	NIL	d1.19	NIL	34	6/30	d.78	d.32	9/30	NIL	NIL	YES
2527	Signature Bank (NDQ)	SBNY	116.57	3	3	4	1.05	175- 265	(50-125%)	10.3	1.9	11.30	2.24	37	6/30	2.72	2.83	9/30	.56	.56	YES
1039 2187	Signet Jewelers Ltd.	SIG	17.03	5	3	5	1.15	55- 80	(225-370%)	5.7	9.1	2.97	1.55	91	7/31	.51	.52	12/31	.37	.37	YES
1180	Silgan Holdings (NDQ)	SLGN	29.70	3	3	2	.95	35- 50	(20- 70%)	15.0	1.5	1.98	.44	41	6/30	.28	.50	9/30	.11	.10	YES
1378	Silicon Labs. (NDQ)	SLAB	108.34	3	3	2	1.20	85- 130	(N- 20%)	81.5	NIL	1.33	NIL	73	6/30	d.37	.32	9/30	NIL	NIL	YES
1547	Simon Property Group	SPG	152.36	3	2	5	.80	220- 300	(45- 95%)	21.6	5.7	7.07	8.65	33	6/30	1.60	1.77	9/30	▲2.10	2.00	YES
1938	Simply Good Foods (NDQ)	SMPL	28.54	–	3	–	NMF	15- 25	(N- N%)	42.6	NIL	.67	NIL	46	5/31	.16	.10	9/30	NIL	NIL	YES
1118	Simpson Manufacturing	SSD	68.13	3	3	3	1.00	70- 105	(5- 55%)	21.6	1.4	3.15	.92	49	6/30	.88	.94	12/31	.23	.22	YES
2342	Sinclair Broadcast (NDQ)	SBGI	42.26	2	3	2	1.25	55- 80	(30- 90%)	16.4	2.0	2.57	.85	72	6/30	.45	.27	9/30	.20	.18	YES
2343	Sirius XM Holdings (NDQ)	SIRI	6.18	3	4	3	1.00	18- 30	(190-385%)	18.2	0.8	.34	.05	72	6/30	.06	.06	9/30	.012	.011	YES
1548	SITE Centers	SITC	14.82	3	3	3	.90	11- 17	(N- 15%)	74.1	5.4	.20	.80	33	6/30	.05	d.07	12/31	.20	.20	YES
2188	SiteOne Landscape	SITE	72.25	2	3	1	.95	70- 110	(N- 50%)	34.6	NIL	2.09	NIL	91	6/30	1.52	1.48	9/30	NIL	NIL	YES
2321	Six Flags Entertainment	SIX	51.52	3	3	3	.90	70- 105	(35-105%)	18.9	6.4	2.72	3.30	36	6/30	.94	.88	9/30	.82	.78	YES
2161	Skechers U.S.A.	SKX	36.57	2	3	3	1.35	60- 85	(65-130%)	15.0	NIL	2.44	NIL	38	6/30	.49	.29	9/30	NIL	NIL	YES
311	SkyWest (NDQ)	SKYW	56.45	3	3	2	1.40	75- 110	(35- 95%)	9.0	0.9	6.27	.48	65	6/30	1.71	1.43	12/31	.12	.10	YES
1379	Skyworks Solutions (NDQ)	SWKS	77.41	4	3	3	1.15	105- 155	(35-100%)	13.2	2.3	5.85	1.76	73	6/30	1.35	1.64	9/30	▲.44	.38	YES
1838	Slack Technologies	WORK	22.87	–	3	–	NMF	30- 45	(30- 95%)	NMF	NIL	d.85	NIL	54	7/31	d.66	NA	9/30	NIL	NIL	YES
2669 2189	Sleep Number Corp. (NDQ)	SNBR	40.68	3	3	2	1.15	65- 95	(60-135%)	15.6	NIL	2.60	NIL	91	6/30	.14	.10	9/30	NIL	NIL	YES
1731	Smith (A.O.)	AOS	46.81	3	3	3	1.20	▼ 55- 80	(15- 70%)	19.0	1.9	▼2.47	.88	23	6/30	.61	.66	9/30	.22	.18	YES
849 1939	Smucker (J.M.)	SJM	107.96	3	1	3	.70	140- 170	(30- 55%)	15.3	3.3	7.05	3.52	46	7/31	1.36	1.17	9/30	▲.88	.85	YES
2462 2653	Snap Inc.	SNAP	15.52	–	4	–	NMF	12- 20	(N- 30%)	NMF	NIL	d.56	NIL	55	6/30	d.19	d.27	9/30	NIL	NIL	YES
1732	Snap-on Inc.	SNA	154.78	3	2	4	1.15	180- 245	(15- 60%)	12.2	2.8	12.64	4.40	23	6/30	3.22	3.12	9/30	.95	.82	YES
2132	Sonic Automotive	SAH	30.22	2	3	3	1.30	25- 40	(N- 30%)	14.9	1.4	2.03	.42	4	6/30	.62	.35	12/31	.10	.06	YES
1181	Sonoco Products	SON	57.99	3	2	3	1.00	60- 80	(5- 40%)	16.1	3.0	3.60	1.72	41	6/30	.95	.93	9/30	.43	.41	YES
1344	Sonos, Inc. (NDQ)	SONO	13.03	–	3	–	NMF	16- 25	(25- 90%)	NMF	NIL	.07	NIL	74	6/30	d.13	d.23	9/30	NIL	NIL	YES
1988	Sony Corp. ADR(g)	SNE	57.96	3	3	3	1.15	60- 90	(5- 55%)	12.5	0.7	4.65	.40	60	6/30	1.10	1.57	9/30	NIL	NIL	YES
★★ 2190	Sotheby's	BID	SEE FINAL SUPPLEMENT																		
554	South Jersey Inds.	SJI	32.28	3	2	3	.80	35- 45	(10- 40%)	26.7	3.8	1.21	1.23	52	6/30	d.13	.07	12/31	.288	.567	YES
146	Southern Co.	SO	61.88	3	2	3	.50	50- 70	(N- 15%)	19.6	4.1	3.16	2.52	14	6/30	.80	.71	9/30	.62	.60	YES
1595	Southern Copper	SCCO	33.10	4	3	3	1.25	65- 95	(95-185%)	15.2	4.8	2.18	1.60	89	6/30	.52	.53	9/30	.40	.40	YES
312	Southwest Airlines	LUV	53.37	3	3	3	1.20	80- 120	(50-125%)	11.7	1.3	4.55	.72	65	6/30	1.37	1.27	9/30	.18	.16	YES
555	Southwest Gas	SWX	90.07	3	3	3	.70	75- 110	(N- 20%)	21.8	2.5	4.13	2.25	52	6/30	.41	.44	12/31	◆.545	.52	YES
544	Southwestern Energy	SWN	1.89	5	4	3	1.55	12- 20	(535-960%)	3.2	NIL	.60	NIL	92	6/30	.08	.18	9/30	NIL	NIL	YES
164	Spartan Motors (NDQ)	SPAR	13.57	3	3	3	1.00	18- 25	(35- 85%)	21.2	0.7	.64	.10	59	6/30	.15	.12	9/30	NIL	NIL	YES
453 1956	SpartanNash Co. (NDQ)	SPTN	11.64	5	3	4	1.20	25- 40	(115-245%)	8.2	6.5	1.42	.76	22	6/30	.34	.50	9/30	.19	.18	YES
1779	Spectrum Brands	SPB	52.25	–	3	–	NMF	55- 85	(5- 65%)	15.6	3.2	3.34	1.68	45	6/30	1.35	11.89	9/30	.42	NIL	YES
1421 2322	Speedway Motorsports	TRK	SEE FINAL SUPPLEMENT																		
556	Spire Inc.	SR	86.15	3	2	3	.65	75- 105	(N- 20%)	26.2	2.8	3.29	2.37	52	6/30	d.09	.52	12/31	.593	.563	YES
721	Spirit AeroSystems	SPR	81.40	4	3	5	1.20	110- 165	(35-105%)	11.7	0.6	6.97	.48	44	6/30	1.71	1.63	12/31	.12	.12	YES
313	Spirit Airlines	SAVE	35.88	3	3	3	1.20	75- 110	(110-205%)	6.3	NIL	5.66	NIL	65	6/30	1.69	1.11	9/30	NIL	NIL	YES
645 1839	Splunk Inc. (NDQ)	SPLK	117.07	3	3	3	1.60	150- 225	(30- 90%)	NMF	NIL	▼d.96	NIL	54	7/31	d.67	d.71	9/30	NIL	NIL	YES
2344	Spotify Tech. S.A.	SPOT	112.52	–	4	–	NMF	175- 260	(55-130%)	NMF	NIL	d1.57	NIL	72	6/30	d.47	d2.52	9/30	NIL	NIL	YES
2670 930	Sprint Corp.	S	6.16	–	4	–	1.15	10- 17	(60-175%)	NMF	NIL	.05	NIL	43	6/30	d.03	.04	9/30	NIL	NIL	YES
1957	Sprouts Farmers Market (NDQ)	SFM	19.18	4	3	4	.85	30- 50	(55-160%)	18.8	NIL	1.02	NIL	22	6/30	.30	.32	9/30	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

STOCK PRICES

	September		
	2019	2014	2009
ATO	111.44	49.44	28.57
CPK	94.31	43.59	20.48
NJR	45.01	25.55	18.10
NI	29.57	15.58	5.41
NWN	71.25	43.83	42.37
OGS	92.76	36.24	
SJI	32.68	27.56	17.93
SWX	90.92	50.99	25.74
SR	86.23	47.86	32.33
Check	654.17	340.65	190.93
Check	654.17	340.65	190.93

Note: All data in worksheet; rows not used hidden.

	ATO	CPK	NJR	NI	NWN	OGS	SJI	SWX	SR	UGI
9/21/2009	28.43	20.17	18.24	5.29	42.29		17.49	26.26	33.05	17.09
9/22/2009	28.19	20.44	18.41	5.30	41.94		17.41	26.06	32.93	17.03
9/23/2009	28.24	20.39	18.11	5.35	41.61		17.43	26.05	32.55	16.81
9/24/2009	28.19	20.02	18.10	5.36	41.78		17.42	25.84	32.37	16.79
9/25/2009	28.10	20.43	18.06	5.38	41.91		17.46	25.70	32.25	16.74
9/28/2009	28.31	20.96	18.26	5.42	42.12		17.76	26.11	32.34	16.81
9/29/2009	28.27	20.86	18.29	5.47	41.82		17.73	26.03	32.80	16.93
9/30/2009	28.18	20.66	18.16	5.46	41.66		17.65	25.58	32.16	16.71
10/1/2009	27.78	20.19	17.79	5.34	41.50		17.65	25.49	32.07	16.59
10/2/2009	27.68	19.89	17.71	5.29	40.94		17.63	25.31	31.90	16.33
10/5/2009	28.45	19.85	17.69	5.37	41.18		17.93	25.43	31.85	16.58
10/6/2009	28.52	20.10	17.92	5.38	41.77		17.97	25.76	31.96	16.55
10/7/2009	28.74	20.42	17.99	5.40	41.98		17.83	25.71	31.79	16.41
10/8/2009	28.91	20.21	17.86	5.46	42.07		18.05	25.74	31.74	16.45
10/9/2009	28.90	20.45	18.01	5.49	42.43		18.11	26.06	32.27	16.54
10/12/2009	29.21	20.42	18.17	5.53	43.03		18.14	25.92	32.36	16.59
10/13/2009	29.00	21.01	18.05	5.49	43.42		18.32	25.87	32.51	16.42
10/14/2009	28.82	20.95	18.14	5.45	43.24		18.38	25.69	32.56	16.47
10/15/2009	29.01	20.59	18.26	5.45	43.40		18.37	25.63	32.80	16.62
10/16/2009	28.90	20.77	18.22	5.44	43.39		18.46	25.36	32.25	16.48
10/19/2009	29.30	20.93	18.42	5.49	44.47		18.71	25.41	32.37	16.90
10/20/2009	29.34	20.86	18.38	5.42	44.23		18.61	25.34	32.39	16.88
Sep 2009 Avg.	**28.57**	**20.48**	**18.10**	**5.41**	**42.37**		**17.93**	**25.74**	**32.33**	**16.67**
9/2/2014	50.33	46.19	26.00	15.59	45.10	37.25	28.79	52.22	49.53	35.35
9/3/2014	50.76	45.87	25.98	15.64	45.16	37.00	28.68	52.34	49.37	35.61
9/4/2014	50.54	45.89	25.90	15.66	45.08	37.06	28.67	52.57	49.38	35.40
9/5/2014	51.31	46.30	26.43	15.88	45.46	37.36	28.89	52.83	49.56	35.91
9/8/2014	51.31	46.27	26.17	15.87	45.19	37.42	28.56	52.76	49.35	36.33
9/9/2014	50.59	45.11	25.96	15.79	44.75	36.99	28.40	52.28	48.30	35.99
9/10/2014	50.17	45.21	25.79	15.70	44.53	36.90	28.05	52.12	48.36	35.70
9/11/2014	50.46	45.20	25.94	15.72	44.85	37.18	28.11	52.74	48.79	35.73
9/12/2014	49.61	43.76	25.36	15.34	43.82	36.21	27.59	51.76	47.71	35.04
9/15/2014	49.83	43.44	25.30	15.30	43.73	36.05	27.57	51.35	47.48	34.95
9/16/2014	50.13	43.53	25.63	15.51	43.89	36.39	27.68	51.43	47.81	35.16
9/17/2014	49.86	43.03	25.43	15.47	43.64	36.28	27.35	50.97	48.06	35.04
9/18/2014	49.39	43.12	25.20	15.42	43.48	36.36	27.22	50.83	48.00	34.97
9/19/2014	49.24	42.69	25.25	15.62	43.33	36.67	27.25	50.49	47.80	35.08
9/22/2014	48.90	41.93	25.06	15.43	43.11	35.93	26.96	49.98	47.33	34.41
9/23/2014	48.29	40.80	25.01	15.46	42.45	35.85	26.37	49.40	46.75	33.94
9/24/2014	47.74	40.65	25.14	15.36	42.84	35.40	26.53	49.21	46.33	33.97
9/25/2014	47.25	39.96	25.24	15.19	42.54	34.95	26.43	48.93	46.05	33.71
9/26/2014	47.01	42.35	25.29	15.16	42.58	34.78	26.51	49.05	46.35	34.05
9/29/2014	47.84	42.45	25.34	16.05	42.71	34.70	26.59	48.90	46.36	34.21
9/30/2014	47.70	41.66	25.26	16.10	42.25	34.25	26.68	48.58	46.40	34.09
Sep 2014 Avg.	**49.44**	**43.59**	**25.55**	**15.58**	**43.83**	**36.24**	**27.56**	**50.99**	**47.86**	**34.98**
9/3/2019	111.77	94.97	45.82	30.06	71.64	92.18	32.46	91.48	85.71	48.14
9/4/2019	110.96	95.49	45.88	30.21	71.71	92.08	32.79	91.14	85.65	48.02
9/5/2019	109.68	95.53	46.08	29.67	71.24	91.52	33.12	90.91	85.74	48.07
9/6/2019	109.09	94.21	45.21	29.33	70.55	89.82	32.80	90.07	85.27	48.00
9/9/2019	107.74	93.06	43.89	28.91	70.11	88.78	32.38	89.46	84.61	48.35
9/10/2019	108.80	92.64	43.82	28.97	69.89	89.08	32.60	89.81	84.59	48.70
9/11/2019	109.57	94.10	45.35	29.14	71.64	91.04	33.27	91.17	86.44	49.15
9/12/2019	109.44	93.60	45.08	29.11	72.03	91.08	32.72	91.84	86.48	49.31
9/13/2019	109.73	93.46	45.10	29.04	71.81	91.52	32.75	92.00	86.99	49.73
9/16/2019	110.11	93.63	44.78	29.04	71.44	91.66	32.42	92.14	86.20	50.33
9/17/2019	110.96	93.78	44.67	29.43	71.29	91.91	32.26	91.71	86.26	50.05
9/18/2019	111.80	93.90	44.87	29.47	71.52	93.11	32.67	91.00	86.43	50.45
9/19/2019	112.28	94.39	44.47	29.44	71.90	94.01	33.02	91.10	86.74	50.46
9/20/2019	112.98	94.09	44.36	29.48	71.42	94.16	32.31	91.51	86.27	49.77
9/23/2019	112.59	93.48	44.99	29.62	70.71	94.44	32.76	90.51	86.14	50.27
9/24/2019	114.29	94.04	45.01	29.96	70.85	95.31	32.54	90.27	87.17	50.63
9/25/2019	114.42	95.84	45.43	30.07	71.27	95.91	32.56	90.80	87.00	50.87
9/26/2019	114.65	95.12	45.13	30.56	71.32	96.27	32.74	90.40	87.18	50.73
9/27/2019	114.05	95.47	45.01	30.03	71.33	95.25	32.50	90.00	86.58	50.45
9/30/2019	113.89	95.32	45.22	29.92	71.34	96.11	32.91	91.04	87.24	50.27
Sep 2019 Avg.	**111.44**	**94.31**	**45.01**	**29.57**	**71.25**	**92.76**	**32.68**	**90.92**	**86.23**	**49.59**

ATMOS ENERGY CORP (ATO-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

THOMSON REUTERS STOCKREPORTS+
COMPANY IN CONTEXT REPORT

Report Date: 2019 October 11

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
110.85 (USD)	**674,432**	**115.19**	**26.2**	**2.10**	**9.4%**	**7.0%**	**1.9%**
2019 October 10 NEW YORK Exchange	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
	13.4B	**87.88**	**23.8**	**1.9%**	**2.9B**	**86.0%**	**3.8%**

VERUS OPINION

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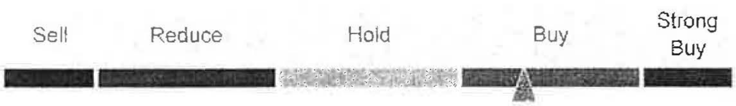
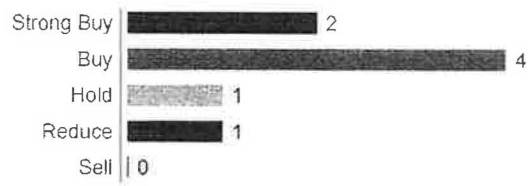
verus analytics

THOMSON REUTERS I/B/E/S MEAN

Buy
8 Analysts

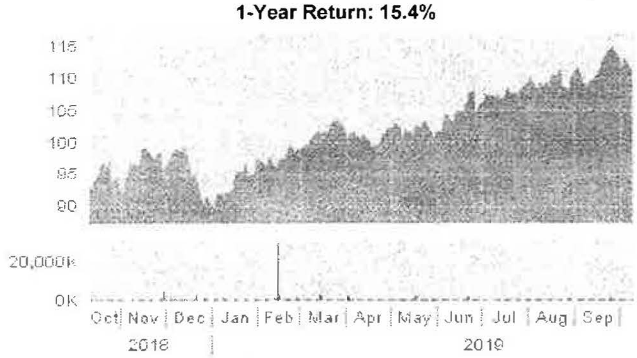
Mean recommendation from all analysts covering the company as provided to Thomson Reuters and then standardized to a 5-point scale.



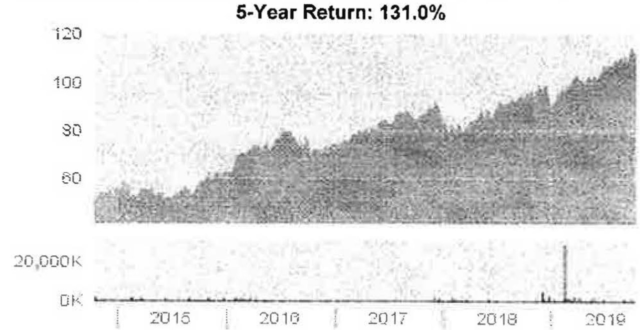


PRICE AND VOLUME CHARTS

1-Year Return: 15.4%



5-Year Return: 131.0%



BUSINESS SUMMARY

Atmos Energy Corporation. Atmos Energy Corporation is a fully-regulated, natural-gas-only distributor engaged primarily in the regulated natural gas distribution and pipeline businesses, as well as other nonregulated natural gas businesses. It operates through three segments: regulated distribution segment, which includes its regulated distribution and related sales operations; regulated pipeline segment, which includes pipeline and storage operations of its Atmos Pipeline-Texas Division, and nonregulated segment, which includes its nonregulated natural gas management, nonregulated natural gas transmission, storage and other services. Its nonregulated businesses provide natural gas management, transportation and storage services to local gas distribution companies, including certain of its natural gas distribution divisions and industrial customers in the Midwest and Southeast. It also manages its natural gas pipeline and storage assets, including its intrastate natural gas pipeline systems in Texas.

THOMSON REUTERS

CHESAPEAKE UTILITIES CORP (CPK-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

THOMSON REUTERS STOCKREPORTS+
COMPANY IN CONTEXT REPORT

Report Date: 2019 October 11

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
93.52 (USD)	**60,316**	**97.00**	**25.6**	**--**	**11.5%**	**--**	**0.9%**
2019 October 10 NEW YORK Exchange	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
	1.6B	**77.20**	**25.4**	**1.7%**	**700M**	**66.8%**	**-0.7%**

VERUS OPINION

Hold

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THOMSON REUTERS I/B/E/S MEAN

Hold
5 Analysts

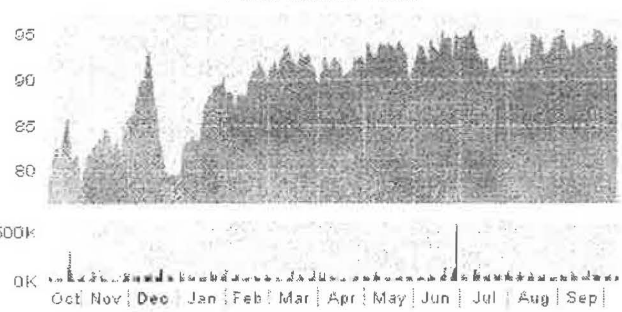
Mean recommendation from all analysts covering the company as provided to Thomson Reuters and then standardized to a 5-point scale.

Sell | Reduce | Hold | Buy | Strong Buy

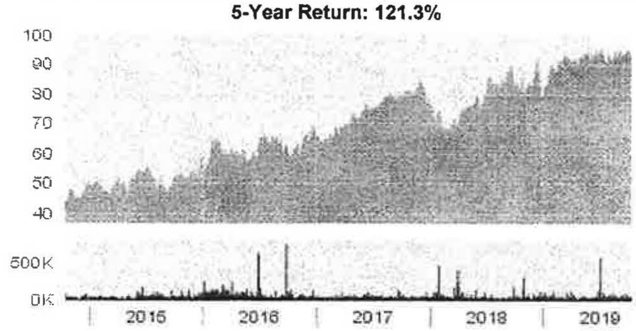
Strong Buy	0
Buy	1
Hold	4
Reduce	0
Sell	0

PRICE AND VOLUME CHARTS

1-Year Return: 11.0%



5-Year Return: 121.3%



BUSINESS SUMMARY

Chesapeake Utilities Corporation (Chesapeake) is an energy company. The Company operates through two segments: Regulated Energy and Unregulated Energy. The Company provides natural gas distribution and transmission; electric distribution and generation; propane distribution; propane and crude oil wholesale marketing; steam generation, and other energy-related services. The Regulated Energy segment includes the Company's natural gas distribution, natural gas transmission and electric distribution operations. The Unregulated Energy segment includes its propane distribution, propane and crude oil wholesale marketing, gathering and processing, electricity and steam generation and other unregulated energy-related services to customers.

THOMSON REUTERS

NEW JERSEY RESOURCES CORP (NJR-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

THOMSON REUTERS STOCKREPORTS+
COMPANY IN CONTEXT REPORT

Report Date: 2019 October 11

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
43.67 (USD)	**414,926**	**51.83**	**28.7**	**1.17**	**8.9%**	**--**	**-0.3%**
2019 October 10 NEW YORK Exchange	Market Cap **3.9B**	52-Week Low **42.74**	Forward PE **17.7**	Dividend Yield **2.9%**	Annual Rev **2.8B**	Inst Own **69.2%**	3-Mo Return **-11.9%**

VERUS OPINION

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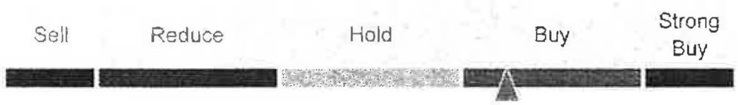
THOMSON REUTERS I/B/E/S MEAN

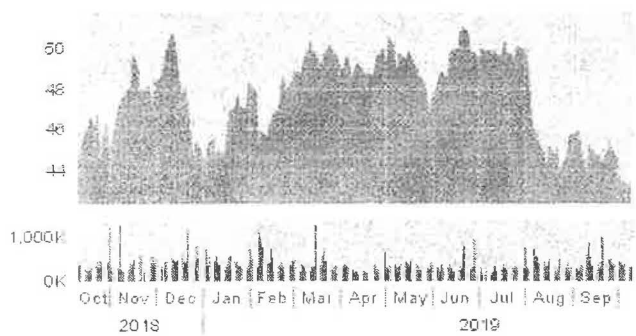
Buy
5 Analysts

Mean recommendation from all analysts covering the company as provided to Thomson Reuters and then standardized to a 5-point scale.

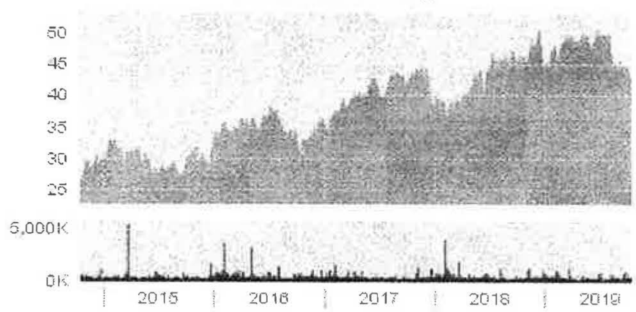


PRICE AND VOLUME CHARTS

1-Year Return: -7.1%



5-Year Return: 73.0%



BUSINESS SUMMARY

New Jersey Resources Corporation is an 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. It operates in four business segments: Natural Gas Distribution, Clean Energy Ventures, Energy Services and Midstream. The Natural Gas Distribution segment consists of regulated natural gas services, off-system sales, capacity and storage management operations. Its Energy Services segment consists of unregulated wholesale energy operations. The Clean Energy Ventures segment consists of capital investments in clean energy projects. Its Midstream segment consists of investments in the midstream natural gas market, such as natural gas transportation and storage facilities. The Home Services and Other operations consist of heating, cooling and water appliance sales and installations, among others.

THOMSON REUTERS

NISOURCE INC (NI-N)

Utilities / Multiline Utilities / Multiline Utilities

THOMSON REUTERS STOCKREPORTS+
COMPANY IN CONTEXT REPORT

Report Date: 2019 October 11

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
29.01 (USD)	**2.4M**	**30.67**	**93.6**	**0.80**	**3.2%**	**4.7%**	**0.1%**
2019 October 10 NEW YORK Exchange	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
	11.1B	**24.19**	**21.6**	**2.8%**	**5.2B**	**95.0%**	**-1.7%**

VERUS OPINION

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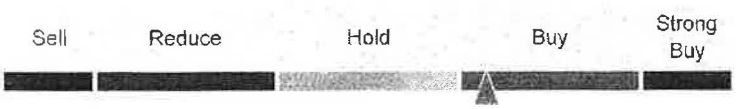
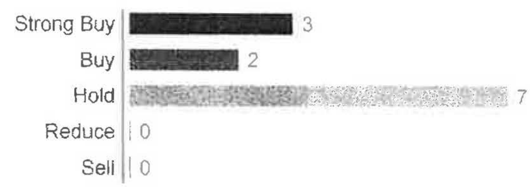
verus analytics

THOMSON REUTERS I/B/E/S MEAN

Buy
12 Analysts

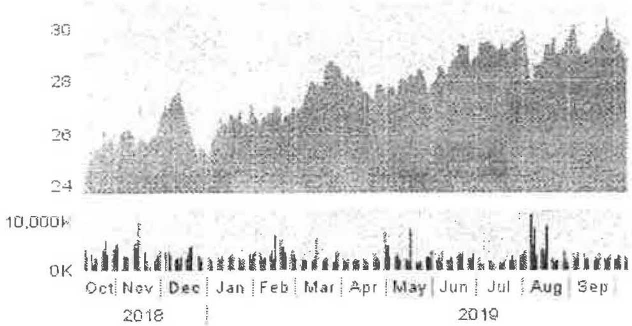
Mean recommendation from all analysts covering the company as provided to Thomson Reuters and then standardized to a 5-point scale.



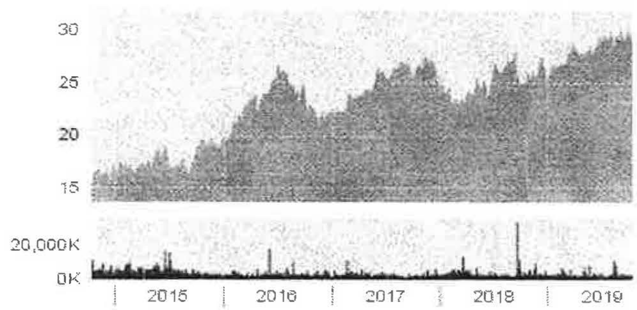


PRICE AND VOLUME CHARTS

1-Year Return: 15.7%



5-Year Return: 82.0%



BUSINESS SUMMARY

NiSource Inc.. NiSource Inc. is an energy holding company. The Company is engaged in the distribution of natural gas. The Company operates through two business segments: Gas Distribution Operations and Electric Operations. The Company's Gas Distribution Operations segment provides natural gas service and transportation for residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, Maryland, Indiana and Massachusetts. As of December 31, 2016, the Company's Electric Operations segment provided electric services in 20 counties in the northern part of Indiana. The Company's electric operations segment generated, transmitted and distributed electricity through the Company's subsidiary NIPSCO to approximately 466,000 customers in 20 counties in the northern part of Indiana and engaged in wholesale and transmission transactions, as of December 31, 2016. NIPSCO owned and operated three coal-fired electric generating stations, as of December 31, 2016.

NORTHWEST NATURAL HOLDING CO (NWN-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

THOMSON REUTERS STOCKREPORTS+
COMPANY IN CONTEXT REPORT

Report Date: 2019 October 11

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
69.50 (USD)	**141,742**	**73.50**	**29.5**	**1.91**	**8.4%**	**4.0%**	**-0.6%**
2019 October 10 NEW YORK Exchange	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
	2.1B	**57.20**	**28.6**	**2.8%**	**727M**	**72.3%**	**-1.0%**

VERUS OPINION

Buy

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THOMSON REUTERS I/B/E/S MEAN

Hold
4 Analysts

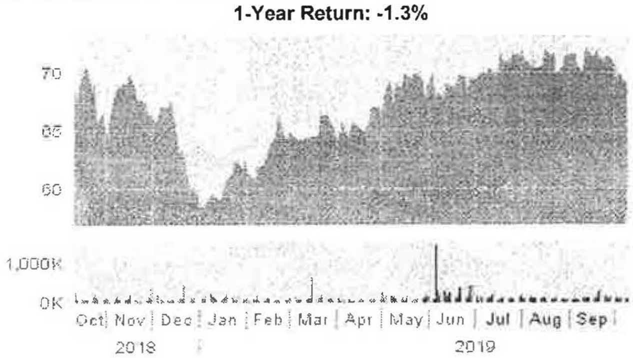
Mean recommendation from all analysts covering the company as provided to Thomson Reuters and then standardized to a 5-point scale.

Sell | Reduce | Hold | Buy | Strong Buy

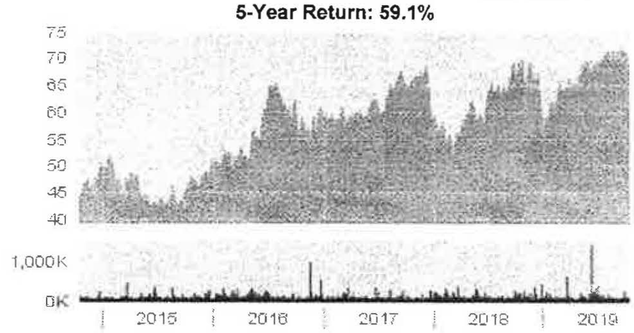
Strong Buy	0
Buy	1
Hold	2
Reduce	0
Sell	1

PRICE AND VOLUME CHARTS

1-Year Return: -1.3%



5-Year Return: 59.1%



BUSINESS SUMMARY

Northwest Natural Holding Co Formerly known as Northwest Natural Gas Company. Northwest Natural Holding Company is a holding company. It operates through its subsidiaries as a provider of natural gas services. It provides its services to residential, commercial and industrial customers in Oregon and Southwest Washington. Its local gas distribution involves the distribution and sale of natural gas to customers in Oregon and Southwest Washington, and includes the utility portion of its underground natural gas storage facility in Mist, Oregon, and the north Mist gas storage expansion in Oregon. Its gas storage segment represents natural gas storage services provided to intrastate and interstate customers from the non-utility portion of the Mist underground storage facility, the Gill Ranch storage facility, and asset management services. Its other segment consists of an investment in a natural gas pipeline project, its natural gas retail appliance store, and other non-utility business development and other activities.

THOMSON REUTERS

ONE GAS INC (OGS-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

THOMSON REUTERS STOCKREPORTS+
COMPANY IN CONTEXT REPORT

Report Date: 2019 October 11

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
94.23 (USD)	**261,100**	**96.66**	**28.0**	**2.00**	**8.7%**	**--**	**5.8%**
2019 October 10 NEW YORK Exchange	Market Cap **5.0B**	52-Week Low **75.51**	Forward PE **27.3**	Dividend Yield **2.1%**	Annual Rev **1.7B**	Inst Own **76.6%**	3-Mo Return **2.9%**

VERUS OPINION

Hold

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verus analytics

THOMSON REUTERS I/B/E/S MEAN

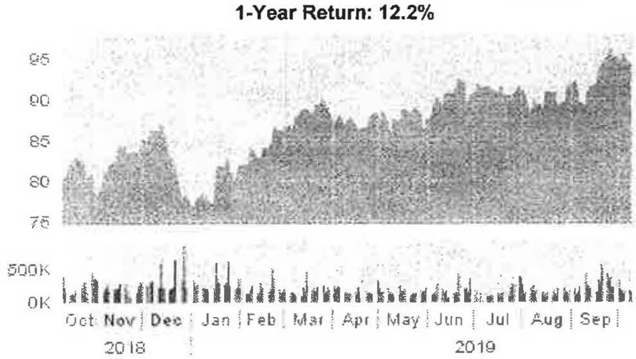
Hold
4 Analysts

Mean recommendation from all analysts covering the company as provided to Thomson Reuters and then standardized to a 5-point scale.

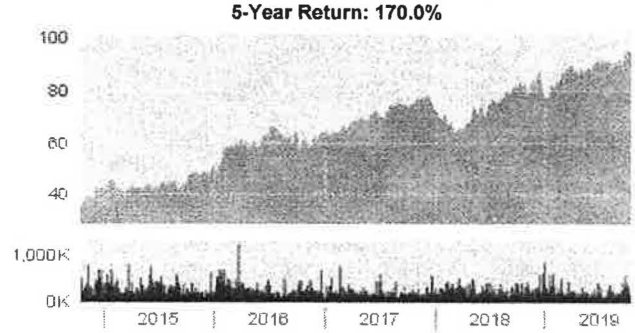
Sell | Reduce | Hold | Buy | Strong Buy

PRICE AND VOLUME CHARTS

1-Year Return: 12.2%



5-Year Return: 170.0%



BUSINESS SUMMARY

One Gas Inc. ONE Gas, Inc. is a regulated natural gas distribution utility in the United States. The Company provides natural gas distribution services. The Company distributes natural gas in Oklahoma, Kansas and Texas. The Company serves residential, commercial and industrial, transportation and wholesale and public authority 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. As of December 31, 2016, 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. As of December 31, 2016, the Company had 50.4 billion cubic feet (Bcf) of natural gas storage capacity under lease with remaining terms ranging from 1 to 10 years and maximum allowable daily withdrawal capacity of approximately 1.3 Bcf.

SOUTH JERSEY INDUSTRIES INC (SJI-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

THOMSON REUTERS STOCKREPORTS+
COMPANY IN CONTEXT REPORT
Report Date: 2019 October 11

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
32.35 (USD)	**525,995**	**35.68**	**39.5**	**1.15**	**5.2%**	**--**	**-0.8%**
2019 October 10 NEW YORK Exchange	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
	3.0B	**26.06**	**25.3**	**3.6%**	**1.8B**	**83.3%**	**-4.3%**

VERUS OPINION

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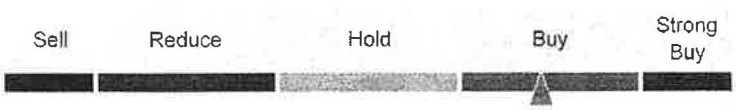
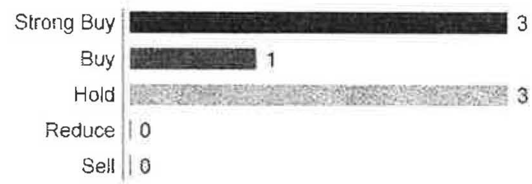
verus analytics

THOMSON REUTERS I/B/E/S MEAN

Buy
7 Analysts

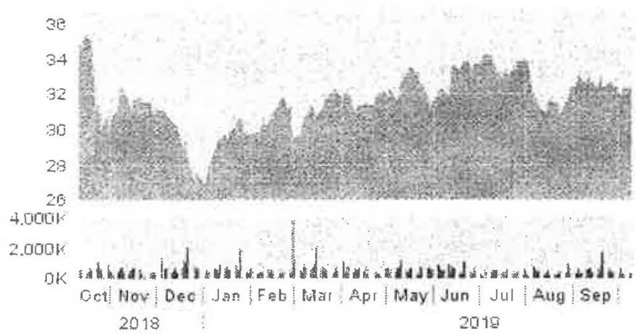
Mean recommendation from all analysts covering the company as provided to Thomson Reuters and then standardized to a 5-point scale.



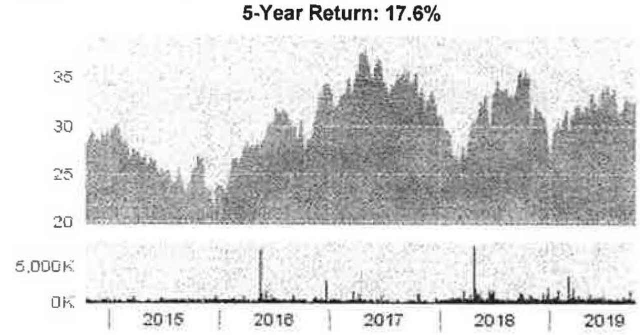


PRICE AND VOLUME CHARTS

1-Year Return: -10.2%



5-Year Return: 17.6%



BUSINESS SUMMARY

South Jersey Industries, Inc. (SJI) is an energy services holding company. The Company provides a range of energy-related products and services, primarily through its subsidiaries. Its subsidiaries include South Jersey Gas Company (SJG), South Jersey Energy Company (SJE), South Jersey Resources Group, LLC (SJRG), South Jersey Exploration, LLC (SJEX), Marina Energy, LLC (Marina), South Jersey Energy Service Plus, LLC (SJESP) and SJI Midstream, LLC (Midstream). Its segments include Gas utility operations (SJG), which consist primarily of natural gas distribution; Wholesale energy operations, which include the activities of SJRG and SJEX; SJE, which is involved in both retail gas and retail electric activities; On-Site energy production, which consists of Marina's thermal energy facility; Appliance service operations, which include SJESP, and Corporate and Services segment, which includes the activities of Midstream.

THOMSON REUTERS

Symbol	Company Name	Security Type	Security Price	I/B/E/S Estimates from Refinitiv	Forward EPS Long Term Growth (3-5 Yrs)
ATO	Atmos Energy Corp	Common Stock	111.36	2.222	7
CPK	Chesapeake Utilities Corp.	Common Stock	93.93	2.8	
NJR	New Jersey Resources Corp	Common Stock	43.73	2.2	
NI	NiSource Inc	Common Stock	29.14	2.385	4.664
NWN	Northwest Natural Holding Co	Common Stock	70.36	3.4	4

SOUTHWEST GAS HOLDINGS INC (SWX-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

THOMSON REUTERS STOCKREPORTS+
COMPANY IN CONTEXT REPORT

Report Date: 2019 October 11

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
90.34 (USD)	**262,632**	**92.94**	**23.8**	**2.18**	**9.1%**	**8.2%**	**0.6%**
2019 October 10 NEW YORK Exchange	Market Cap **4.9B**	52-Week Low **72.68**	Forward PE **22.9**	Dividend Yield **2.4%**	Annual Rev **3.0B**	Inst Own **86.7%**	3-Mo Return **-0.8%**

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).

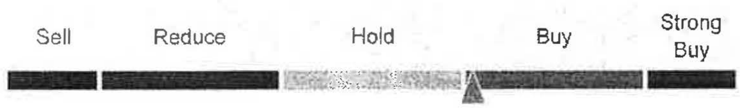
The Verus Opinion covers 4251 companies, with 11.3% rated Buy, 64.7% rated Hold, and 24.0% rated Sell as of 2019-10-04. Verus Analytics Inc is a private independent research firm, unaffiliated with Thomson Reuters, that specializes in engineering institutional ratings systems.

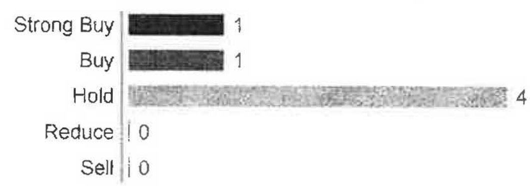
verus analytics

THOMSON REUTERS I/B/E/S MEAN

Buy
6 Analysts

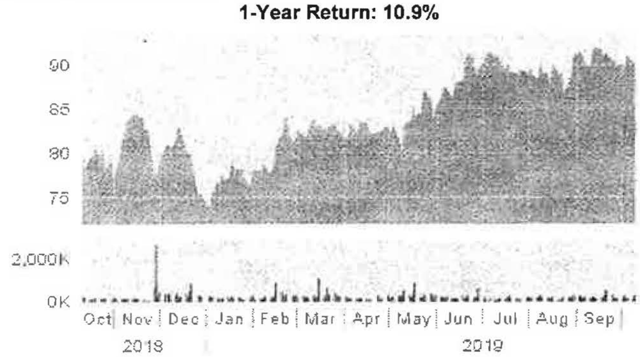
Mean recommendation from all analysts covering the company as provided to Thomson Reuters and then standardized to a 5-point scale.



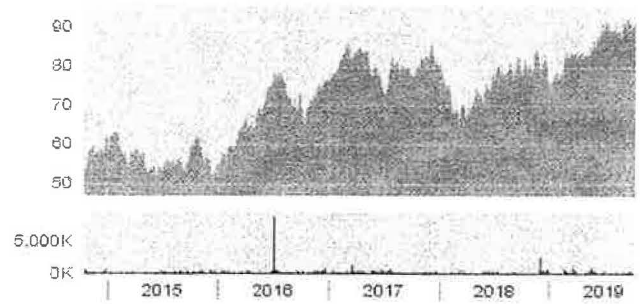


PRICE AND VOLUME CHARTS

1-Year Return: 10.9%



5-Year Return: 75.7%



BUSINESS SUMMARY

Southwest Gas Corporation. Southwest Gas Holdings, Inc., formerly Southwest Gas Corporation, is engaged in the business of purchasing, distributing and transporting natural gas. The Company operates through two segments: natural gas operations and construction services, which includes the operations of the Company's subsidiary, Centuri Construction Group, Inc. (Centuri). The Company operates two pipeline transmission systems, such as a system, which includes a liquefied natural gas (LNG) storage facility owned by Paiute extending from the Idaho-Nevada border to the Reno, Sparks, and Carson City areas and communities in the Lake Tahoe area in both California and Nevada and other communities in northern and western Nevada, and a system extending from the Colorado River at the southern tip of Nevada to the Las Vegas distribution area.

THOMSON REUTERS

SPIRE INC (SR-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

THOMSON REUTERS STOCKREPORTS+
COMPANY IN CONTEXT REPORT
Report Date: 2019 October 11

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
84.79 (USD)	**217,400**	**88.00**	**22.6**	**2.37**	**7.8%**	**3.2%**	**0.2%**
2019 October 10 NEW YORK Exchange	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
	4.4B	**70.53**	**22.2**	**2.8%**	**2.0B**	**81.8%**	**-0.7%**

VERUS OPINION

Sell

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 4251 companies, with 11.3% rated Buy, 64.7% rated Hold, and 24.0% rated Sell as of 2019-10-04. Verus Analytics Inc is a private independent research firm, unaffiliated with Thomson Reuters, that specializes in engineering institutional ratings systems.

verus analytics

THOMSON REUTERS I/B/E/S MEAN

Hold
7 Analysts

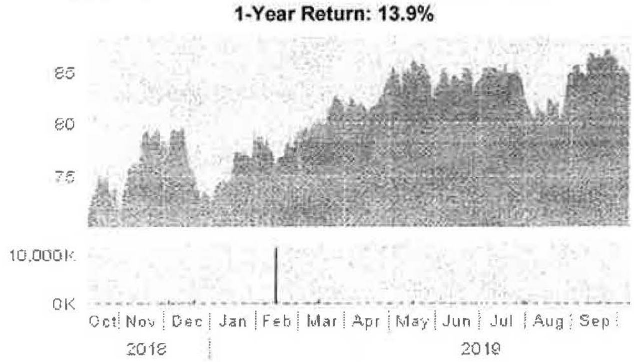
Mean recommendation from all analysts covering the company as provided to Thomson Reuters and then standardized to a 5-point scale.

Sell | Reduce | Hold | Buy | Strong Buy

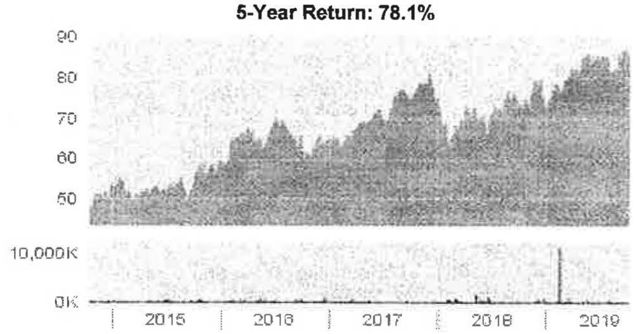
Strong Buy	0
Buy	0
Hold	4
Reduce	3
Sell	0

PRICE AND VOLUME CHARTS

1-Year Return: 13.9%



5-Year Return: 78.1%



BUSINESS SUMMARY

Spire Inc. Spire Inc. is engaged to transform its business and pursue growth by growing its gas utility business through prudent investment in infrastructure upgrades and organic growth initiatives; acquire and integrate gas utilities; modernize its gas assets, and invest in innovation. The Company has two business segments, which include gas utility and gas marketing. The gas utility segment includes the regulated operations Spire Missouri, Spire Alabama, Spire Gulf and Spire Mississippi. The gas marketing segment includes Spire Marketing Inc. (Spire Marketing), a wholly owned subsidiary engaged in the marketing of natural gas and related activities on a non-regulated basis. Mobile Gas and Willmut Gas are subsidiaries of EnergySouth.

THOMSON REUTERS

Symbol	Company Name	Security Type	Security Price	Forward EPS Long Term Growth (3-5 Yrs)
OGS	ONE Gas Inc	Common Stock	95.21	
SJI	South Jersey Industries Inc.	Common Stock	32.57	
SWX	Southwest Gas Holdings Inc	Common Stock	91.44	8.2
SR	Spire Inc	Common Stock	85.51	3.228

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Atmos Energy Corporation (ATO)

(Delayed Data from NYSE)

$111.36 USD

+0.51 (0.46%)

Updated Oct 11, 2019 03:56 PM ET

Add to portfolio | Trades from $1

Zacks Rank: 2-Buy 2

Style Scores: C Value | C Growth | D Momentum | C VGM

Industry Rank: Top 29% (75 out of 255)

Industry: Utility - Gas Distribution

Quote Overview

View All Zacks #1 Ranked Stocks | Enter Symbol

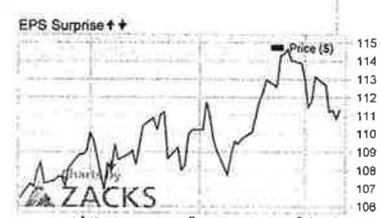
Stock Activity		Key Earnings Data	
Open	111.06	Earnings ESP	0.00%
Day Low	110.51	Most Accurate Est	0.47
Day High	112.02	Current Qtr Est	0.47
52 Wk Low	87.88	Current Yr Est	4.63
52 Wk High	115.19	Exp Earnings Date	*AMC11/6/19
Avg. Volume	678,059	Prior Year EPS	4.00
Market Cap	13.16 B	Exp EPS Growth (3-5yr)	7.00%
Dividend	2.10 (1.89%)	Forward PE	24.07
Beta	0.19	PEG Ratio	3.44

Utilities » Utility - Gas Distribution

*BMO = Before Market Open *AMC = After Market Close

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Reports For ATO

All Zacks' Analyst Reports »

News For ATO

- Zacks News for ATO
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Chesapeake Utilities to Sell Natural Gas Marketing Business
10/10/19-6:50AM EST Zacks

MDU vs. ATO: Which Stock Should Value Investors Buy Now?
09/30/19-8:30AM EST Zacks

ATO: What are Zacks experts saying now?
Zacks Private Portfolio Services

Is Atmos Energy (ATO) Stock Outpacing Its Utilities Peers This...
09/10/19-8:30AM EST Zacks

Why Is Atmos (ATO) Up 0.2% Since Last Earnings Report?
09/06/19-8:31AM EST Zacks

Atmos (ATO) Upgraded to Buy: Here's What You Should Know
08/28/19-8:00AM EST Zacks

More Zacks News for ATO

Atmos Energy Moves Up in Analyst Rankings, Passing Mondelez International 4AM EST ETF Channel

	Company	Industry	SP500
Next Year Estimate	4.63	6.96	176.00

Growth Rates

	Company	Industry	SP500
This Year	8.25	2.30	NA
Next Year	6.93	13.20	NA
Last 5 Years	8.80	2.20	7.40
Next 5 Years	7.00	7.80	NA

Financials

	Company	Industry
Price/Earnings (TTM)	25.96	17.32
Price/Book (MRQ)	2.31	2.09
Price/Cash Flow (MRFY)	15.38	11.49
Dividend Yield	1.89%	2.72%
Net Profit Margin (TTM)	16.94%	NA
Return on Equity (TTM)	9.38%	NA
Debt to Equity (MRQ)	NA	NA

MRQ = Most Recent Quarter

TTM = Trailing Twelve Months

MRFY = Most Recent Fiscal Year

Note: Company and S&P 500 ratios relating to share price calculated daily; all others calculated weekly or in accordance with company earnings announcement. Industry medians calculated weekly.

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Chesapeake Utilities Corporation (CPK)

(Delayed Data from NYSE)

$93.93 USD

+0.41 (0.44%)

Updated Oct 11, 2019 03:58 PM ET

Add to portfolio | Trades from $1

Zacks Rank:
2-Buy 2

Style Scores:
B Value | D Growth | C Momentum | C VGM

Industry Rank:
Top 29% (75 out of 255)

Industry: Utility - Gas Distribution

Quote Overview

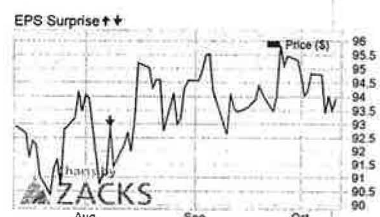
Add to Ranked Stocks | Enter Symbol

Stock Activity		Key Earnings Data	
Open	93.91	Earnings ESP	0.00%
Day Low	93.76	Most Accurate Est	0.37
Day High	95.08	Current Qtr Est	0.37
52 Wk Low	77.20	Current Yr Est	3.72
52 Wk High	97.00	Exp Earnings Date	11/14/19
Avg. Volume	60,429	Prior Year EPS	3.31
Market Cap	1.54 B	Exp EPS Growth (3-5yr)	7.00%
Dividend	1.62 (1.72%)	Forward PE	25.25
Beta	0.19	PEG Ratio	3.61

Utilities » Utility - Gas Distribution

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



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Chesapeake Utilities to Sell Natural Gas Marketing Business
10/10/19-6:50AM EST Zacks

Reasons to Add MDU Resources (MDU) to Your Portfolio Now
09/12/19-10:02AM EST Zacks

CPK: What are Zacks experts saying now?
Zacks Private Portfolio Services

CPK or OKE: Which Utility Stock is Better Placed Right Now?
09/04/19-9:05AM EST Zacks

Here's Why You Should Add ONE Gas (OGS) to Your Portfolio
08/30/19-8:21AM EST Zacks

Here's Why You Should Invest in Atmos Energy (ATO) Stock Now
08/28/19-7:34AM EST Zacks

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NewJersey Resources Corporation (NJR)

(Delayed Data from NYSE)

$43.73 USD

+0.06 (0.14%)

Updated Oct 11, 2019 03:58 PM ET

Add to portfolio

Zacks Rank: 3-Hold 3

Style Scores: C Value | F Growth | B Momentum | D VGM

Industry Rank: Top 29% (75 out of 255)

Industry: Utility - Gas Distribution

Quote Overview

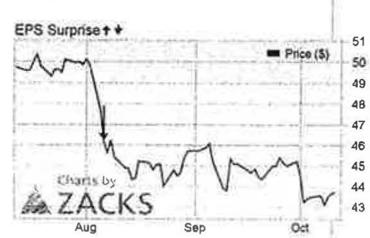
Zacks #1 Ranked Stocks | Enter Symbol

Stock Activity		Key Earnings Data	
Open	43.75	Earnings ESP	0.00%
Day Low	43.67	Most Accurate Est	0.30
Day High	44.61	Current Qtr Est	0.30
52 Wk Low	42.74	Current Yr Est	2.16
52 Wk High	51.83	Exp Earnings Date	11/19/19
Avg. Volume	418,787	Prior Year EPS	2.74
Market Cap	3.93 B	Exp EPS Growth (3-5yr)	8.00%
Dividend	1.25 (2.86%)	Forward PE	20.20
Beta	0.35	PEG Ratio	2.52

Utilities » Utility - Gas Distribution

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



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New Jersey Resources (NJR) Reports Q3 Loss, Misses...
08/06/19-8:35AM EST Zacks

CenterPoint Energy (CNP) to Post Q2 Earnings: What's in Store?
08/05/19-9:15AM EST Zacks

NJR: What are Zacks experts saying now?
Zacks Private Portfolio Services

New Jersey Resources (NJR) Earnings Expected to Grow:...
07/30/19-9:38AM EST Zacks

Can Atmos Energy (ATO) Keep Earnings Streak Alive in Q3?
07/29/19-9:27AM EST Zacks

NJR vs. CPK: Which Stock Is the Better Value Option?
07/05/19-8:00AM EST Zacks

More Zacks News for NJR

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NiSource, Inc (NI)

(Delayed Data from NYSE)

$29.14 USD

+0.13 (0.45%)

Updated Oct 11, 2019 03:58 PM ET

Add to portfolio Trades from ($1)

Zacks Rank: 3-Hold 3

Style Scores: D Value | C Growth | C Momentum | C VGM

Industry Rank: Top 25% (65 out of 255)

Industry: Utility - Electric Power

Quote Overview

All Zacks Ranked Stocks Enter Symbol

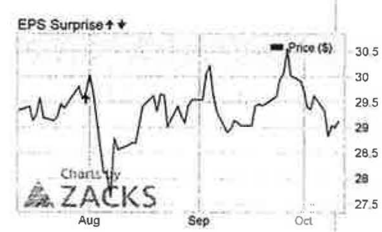
Stock Activity		Key Earnings Data	
Open	28.96	Earnings ESP	0.00%
Day Low	28.90	Most Accurate Est	0.04
Day High	29.39	Current Qtr Est	0.04
52 Wk Low	24.19	Current Yr Est	1.30
52 Wk High	30.67	Exp Earnings Date	*AMC11/7/19
Avg. Volume	2,433,891	Prior Year EPS	1.30
Market Cap	10.88 B	Exp EPS Growth (3-5yr)	5.39%
Dividend	0.80 (2.75%)	Forward PE	22.42
Beta	0.23	PEG Ratio	4.16

Utilities » Utility - Electric Power

*BMO = Before Market Open *AMC = After Market Close

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

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Here's Why You Should Invest in AES Corp (AES) Stock Now
09/30/19-7:59AM EST Zacks

TransAlta (TAC) Announces New Clean Energy Investment Plan
09/17/19-2:19PM EST Zacks

NI What are Zacks experts saying now?
Zacks Private Portfolio Services

Duke Energy Arm Seeks for Rate Hike to Recover Investments
09/06/19-7:04AM EST Zacks

NiSource's (NI) Systematic Long-Term Investments Bode Well
08/30/19-6:53AM EST Zacks

Hawaiian Electric Initiates Largest Clean Energy Procurement
08/28/19-1:14PM EST Zacks

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Northwest Natural Gas Company (NWN)

(Delayed Data from NYSE)

$70.36 USD

+0.86 (1.24%)

Updated Oct 11, 2019 03:58 PM ET

Add to portfolio | Trades from $1

Zacks Rank:
3-Hold 3
Style Scores:
C Value | D Growth | D Momentum | D VGM
Industry Rank:
Top 29% (75 out of 255)
Industry: Utility - Gas Distribution

Quote Overview | View All Zacks #1 Ranked Stocks | Enter Symbol

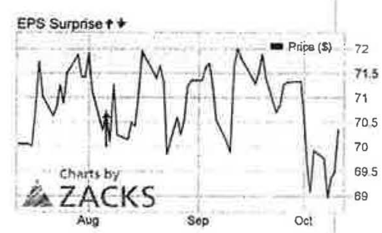
Stock Activity		Key Earnings Data	
Open	69.56	Earnings ESP	NA
Day Low	69.23	Most Accurate Est	NA
Day High	70.97	Current Qtr Est	NA
52 Wk Low	57.20	Current Yr Est	2.35
52 Wk High	73.50	Exp Earnings Date	*BMO 11/5/19
Avg. Volume	144,526	Prior Year EPS	2.33
Market Cap	2.14 B	Exp EPS Growth (3-5yr)	5.00%
Dividend	1.90 (2.70%)	Forward PE	29.94
Beta	0.26	PEG Ratio	5.99

Utilities » Utility - Gas Distribution

*BMO = Before Market Open *AMC = After Market Close

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



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MDU or NWN: Which Is the Better Value Stock Right Now?
09/06/19-8:40AM EST Zacks

CenterPoint Energy (CNP) to Post Q2 Earnings: What's in Store?
08/05/19-9:15AM EST Zacks

NWN: What are Zacks experts saying now?
Zacks Private Portfolio Services

Can Atmos Energy (ATO) Keep Earnings Streak Alive in Q3?
07/29/19-9:27AM EST Zacks

Is a Beat Likely for Southern Company (SO) in Q2 Earnings?
07/29/19-7:28AM EST Zacks

NFG vs. NWN: Which Stock Is the Better Value Option?
07/08/19-8:30AM EST Zacks

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Dividend Kings Analysis: 3M Stands Out
10/12/19-1:08AM EST Seeking Alpha

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ONE Gas, Inc. (OGS)

(Delayed Data from NYSE)

$95.21 USD

+0.98 (1.04%)

Updated Oct 11, 2019 03:58 PM ET

Add to portfolio | Trades from ($1)

Zacks Rank: 3-Hold 3

Style Scores: C Value | C Growth | A Momentum | B VGM

Industry Rank: Top 29% (75 out of 255)

Industry: Utility - Gas Distribution

Quote Overview

Enter Symbol

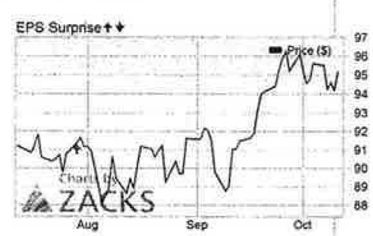
Stock Activity		Key Earnings Data	
Open	94.55	Earnings ESP	0.00%
Day Low	93.75	Most Accurate Est	0.35
Day High	95.76	Current Qtr Est	0.35
52 Wk Low	75.51	Current Yr Est	3.51
52 Wk High	96.66	Exp Earnings Date	*AMC10/28/19
Avg. Volume	261,442	Prior Year EPS	3.25
Market Cap	5.02 B	Exp EPS Growth (3-5yr)	6.13%
Dividend	2.00 (2.10%)	Forward PE	27.15
Beta	0.29	PEG Ratio	4.43

Utilities » Utility - Gas Distribution

*BMO = Before Market Open *AMC = After Market Close

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Reports For OGS

All Zacks' Analyst Reports »

News For OGS

- Zacks News for OGS
- Other News for OGS

What Makes ONE Gas (OGS) a Strong Momentum Stock: Buy...
09/27/19-9:00AM EST Zacks

Here's Why You Should Add ONE Gas (OGS) to Your Portfolio
08/30/19-8:21AM EST Zacks

OGS: What are Zacks experts saying now?
Zacks Private Portfolio Services

ONE Gas (OGS) Down 2.2% Since Last Earnings Report: Can...
08/28/19-8:30AM EST Zacks

Plains All American (PAA) Q2 Earnings Beat, Guidance Up
08/08/19-8:47AM EST Zacks

UGI Corp's (UGI) Earnings & Revenues Miss Estimates in Q3
08/06/19-6:35AM EST Zacks

More Zacks News for OGS

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- Broker Recommendations

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Options
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South Jersey Industries, Inc. (SJI)

(Delayed Data from NYSE)

$32.57 USD

+0.22 (0.68%)

Updated Oct 11, 2019 03:58 PM ET

Add to portfolio | Trades from $1

Zacks Rank: 3-Hold 3
Style Scores: D Value | F Growth | C Momentum | F VGM
Industry Rank: Top 29% (75 out of 255)
Industry: Utility - Gas Distribution

Quote Overview

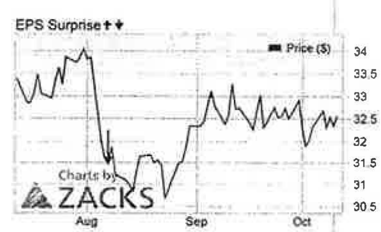
All Zacks #1 Ranked Stocks | Enter Symbol

Stock Activity		Key Earnings Data	
Open	32.47	Earnings ESP	0.00%
Day Low	32.39	Most Accurate Est	-0.27
Day High	33.09	Current Qtr Est	-0.27
52 Wk Low	26.06	Current Yr Est	1.10
52 Wk High	35.68	Exp Earnings Date	11/6/19
Avg. Volume	528,210	Prior Year EPS	1.38
Market Cap	3.01 B	Exp EPS Growth (3-5yr)	8.50%
Dividend	1.15 (3.53%)	Forward PE	29.61
Beta	0.69	PEG Ratio	3.48

Utilities » Utility - Gas Distribution

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Report For SJI

All Zacks' Analyst Reports »

News For SJI

- Zacks News for SJI
- Other News for SJI

South Jersey Industries (SJI) Reports Q2 Loss, Tops Revenue
08/07/19-7:25PM EST Zacks

Weak Near-Term Outlook for Utility Gas Distribution Industry
08/05/19-12:00AM EST Zacks

SJI: What are Zacks experts saying now?
Zacks Private Portfolio Services

Analysts Estimate South Jersey Industries (SJI) to Report a ...
07/31/19-9:36AM EST Zacks

South Jersey Industries (SJI) Q1 Earnings and Revenues Beat ...
05/08/19-7:45PM EST Zacks

Factors Likely to Shape CenterPoint Energy's (CNP) Q1 Earnings
05/07/19-9:30AM EST Zacks

More Zacks News for SJI

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Southwest Gas Corporation (SWX)

(Delayed Data from NYSE)

$91.44 USD

+1.10 (1.22%)

Updated Oct 11, 2019 03:58 PM ET

Add to portfolio | Trades from $1

Zacks Rank: 3-Hold 3

Style Scores: C Value | D Growth | A Momentum | B VGM

Industry Rank: Top 29% (75 out of 255)

Industry: Utility - Gas Distribution

Quote Overview

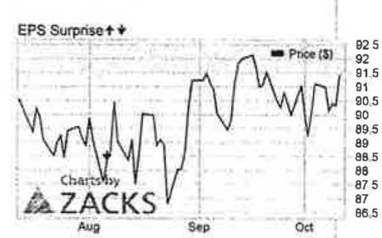
All Zacks Ranked Stocks | Enter Symbol

Stock Activity		Key Earnings Data	
Open	90.78	Earnings ESP	0.00%
Day Low	90.00	Most Accurate Est	0.27
Day High	91.59	Current Qtr Est	0.27
52 Wk Low	72.68	Current Yr Est	3.93
52 Wk High	92.94	Exp Earnings Date	11/5/19
Avg. Volume	261,708	Prior Year EPS	3.68
Market Cap	4.97 B	Exp EPS Growth (3-5yr)	7.25%
Dividend	2.18 (2.38%)	Forward PE	23.24
Beta	0.27	PEG Ratio	3.21

Utilities » Utility - Gas Distribution

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Report For SWX

All Zacks' Analyst Reports »

News For SWX

- Zacks News for SWX
- Other News for SWX

Why Southwest Gas (SWX) is a Great Dividend Stock Right Now
09/30/19-8:15AM EST Zacks

Are You Looking for a High-Growth Dividend Stock? Southwest...
09/12/19-8:15AM EST Zacks

SWX: What are Zacks experts saying now?
Zacks Private Portfolio Services

Why Southwest Gas (SWX) is a Top Dividend Stock for Your...
08/19/19-8:15AM EST Zacks

Sempra Energy's (SRE) Subsidiary Launches Biomethane Project
08/15/19-8:58AM EST Zacks

Why You Should Add Alliant Energy (LNT) to Your Portfolio
08/14/19-10:28AM EST Zacks

More Zacks News for SWX

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Spire Inc. (SR)

(Delayed Data from NYSE)

$85.51 USD

+0.72 (0.85%)

Updated Oct 11, 2019 03:58 PM ET

Add to portfolio | Trades from ($1)

Zacks Rank: 4-Sell 4

Style Scores: C Value | B Growth | B Momentum | C VGM

Industry Rank: Top 29% (75 out of 255)

Industry: Utility - Gas Distribution

Quote Overview

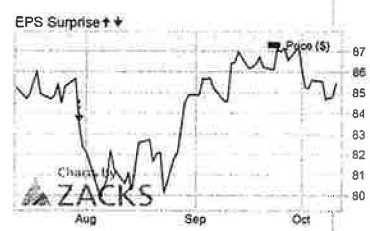
All Zacks Ranked Stocks | Enter Symbol

Stock Activity		Key Earnings Data	
Open	84.94	Earnings ESP	0.00%
Day Low	84.66	Most Accurate Est	-0.53
Day High	85.95	Current Qtr Est	-0.53
52 Wk Low	70.53	Current Yr Est	3.86
52 Wk High	88.00	Exp Earnings Date	11/21/19
Avg. Volume	221,058	Prior Year EPS	3.72
Market Cap	4.34 B	Exp EPS Growth (3-5yr)	5.50%
Dividend	2.37 (2.77%)	Forward PE	22.17
Beta	0.17	PEG Ratio	4.03

Utilities » Utility - Gas Distribution

Price and EPS Surprise Chart

1 Month | 3 Months | YTD



Interactive Chart | Fundamental Chart

Research Report For SR

All Zacks' Analyst Reports »

News For SR

- Zacks News for SR
- Other News for SR

Weak Near-Term Outlook for Utility Gas Distribution Industry
08/05/19-12:00AM EST Zacks

Spire (SR) Misses Q3 Earnings and Revenue Estimates
07/30/19-7:45AM EST Zacks

SR: What are Zacks experts saying now?
Zacks Private Portfolio Services

Earnings Preview: Spire (SR) Q3 Earnings Expected to Decline
07/23/19-9:32AM EST Zacks

Here's Why You Should Add Spire (SR) to Your Portfolio Now
06/11/19-5:14PM EST Zacks

SR vs. NWN: Which Stock Should Value Investors Buy Now?
05/07/19-8:30AM EST Zacks

More Zacks News for SR

Summary Statistics of Annual Total Returns, Income Returns, and Capital Appreciation Returns of Basic U.S. Asset Classes
1926–2018

1926–2018	Geometric Mean Returns (%)	Arithmetic Mean Returns (%)	Standard Deviation of Returns (%)
Large Company Stocks			
Total Return	9.99	11.88	19.76
Income Return	3.94	3.96	1.61
Capital Appreciation Return	5.84	7.69	19.08
Small Company Stocks			
Total Return	11.82	16.21	31.65
Mid-cap Stocks (Decile 3-5)			
Total Return	10.92	13.62	24.25
Income Return	3.72	3.73	1.79
Capital Appreciation Return	7.02	9.67	23.57
Low-cap Stocks (Decile 6-8)			
Total Return	11.30	15.00	28.54
Income Return	3.39	3.41	1.96
Capital Appreciation Return	7.76	11.42	27.90
Micro-cap Stocks (Decile 9-10)			
Total Return	11.88	17.67	38.47
Income Return	2.45	2.46	1.67
Capital Appreciation Return	9.41	15.07	37.65
Long-term Corporate Bonds			
Total Return	5.94	6.25	8.38
Long-term Government Bonds			
Total Return	5.47	5.90	9.83
Income Return	4.94	4.97	2.63
Capital Appreciation Return	0.34	0.71	8.82
Intermediate-term Government Bonds			
Total Return	5.06	5.20	5.60
Income Return	4.35	4.39	2.89
Capital Appreciation Return	0.54	0.64	4.42
US Treasury Bills			
Total Return	3.34	3.38	3.10
Inflation	2.88	2.96	4.02

Source of underlying data: (i) Stocks, Bonds, Bills, and Inflation® (SBBI®) return series from the Morningstar *Direct* database. Series used: Large Company Stocks (IA SBBI US Large Stock TR USD Ext). The "SBBI US Large Stock" return series is essentially the S&P 500 index; Small Company Stocks (IA SBBI US Small Stock TR USD); Long-term Corp. Bonds (IA SBBI US LT Corp TR USD); Long-term Gov't Bonds (IA SBBI US LT Govt TR USD); Intermediate-term Gov't Bonds (IA SBBI US IT Govt TR USD); T-bills (IA SBBI US 30 Day TBill TR USD); Inflation (IA SBBI US Inflation). All rights reserved. Used with permission. (ii) CRSP U.S. Stock Database and CRSP U.S. Indices Database © 2019 Center for Research in Security Prices (CRSP®), University of Chicago Booth School of Business. *CRSP standard market-cap-weighted NYSE/NYSE MKT/NASDAQ deciles 1–10. Mid-cap stocks represented by a market-capitalization weighted portfolio comprised of CRSP deciles 3-5; Low-cap stocks represented by a market-capitalization weighted portfolio comprised of CRSP deciles 6-8; Micro-cap stocks represented by a market-capitalization weighted portfolio comprised of CRSP deciles 9-10. Total return is equal to sum of three components returns: income return, capital appreciation, and reinvestment return. Used with permission. All rights reserved. Calculations performed by Duff & Phelps, LLC.*

				EPS Growth Rates			Market	Weighted			Weighted			Weighted			Weighted	
			Dividend			Value	Cap	Dividend Yield			IBES			Zacks			Value Line	
	Company	Ticker	Yield	IBES	Zacks	Line	($Millions)	Weight	Product	Mkt. Cap.	Weight	Product	Mkt. Cap.	Weight	Product	Mkt. Cap.	Weight	Product
	(a)		(b)	(c)	(d)	(b)	(b)											
1	Equity Residential	EQR	2.7%	2.70%	5.99%	NMF	31,588	0.001497	0.000040	31,588	0.001609	0.000043	31,588	0.001527	0.000091	-	-	-
1	Agilent Technologies, Inc	A	0.9%	10.60%	11.75%	9.50%	24,170	0.001145	0.000010	24,170	0.001231	0.000131	24,170	0.001169	0.000137	24,170	0.001200	0.000114
2	HCP, Inc	HCP	4.2%	2.50%	2.88%	NMF	16,755	0.000794	0.000034	16,755	0.000854	0.000021	16,755	0.000810	0.000023	-	-	-
3	Xilinx, Inc	XLNX	1.4%	12.65%	12.00%	9.50%	26,011	0.001233	0.000018	26,011	0.001325	0.000168	26,011	0.001258	0.000151	26,011	0.001292	0.000123
4	Apartment Investment and Management Company	AIV	3.0%	7.10%	6.20%	NMF	7,859	0.000372	0.000011	7,859	0.000400	0.000028	7,859	0.000380	0.000024	-	-	-
5	Air Products and Chemicals, Inc	APD	2.1%	12.19%	12.14%	9.50%	48,981	0.002321	0.000049	48,981	0.002496	0.000304	48,981	0.002368	0.000288	48,981	0.002432	0.000231
6	L Brands, Inc	LB	6.4%	6.10%	11.50%	NMF	5,208	0.000247	0.000016	5,208	0.000265	0.000016	5,208	0.000252	0.000029	-	-	-
7	Northrop Grumman Corporation	NOC	1.4%	7.90%	12.44%	9.50%	63,588	0.003013	0.000042	63,588	0.003240	0.000256	63,588	0.003075	0.000382	63,588	0.003158	0.000300
8	Gilead Sciences, Inc	GILD	3.8%	2.28%	3.17%	NMF	83,571	0.003960	0.000151	83,571	0.004258	0.000097	83,571	0.004041	0.000128	-	-	-
9	Activision Blizzard, Inc	ATVI	0.7%	6.25%	12.93%	9.50%	42,184	0.001999	0.000015	42,184	0.002149	0.000134	42,184	0.002040	0.000264	42,184	0.002095	0.000199
10	Vornado Realty Trust	VNO	4.2%	17.33%	3.82%	NMF	11,979	0.000568	0.000024	11,979	0.000610	0.000106	11,979	0.000579	0.000022	-	-	-
11	CDW Corporation	CDW	1.0%	13.65%	13.10%	9.50%	17,661	0.000837	0.000008	17,661	0.000900	0.000123	17,661	0.000854	0.000112	17,661	0.000877	0.000083
12	Essex Property Trust, Inc	ESS	2.4%	7.90%	6.36%	NMF	21,541	0.001021	0.000025	21,541	0.001098	0.000087	21,541	0.001042	0.000066	-	-	-
13	Alliance Data Systems Corporation	ADS	1.9%	2.56%	13.50%	9.50%	6,654	0.000315	0.000006	6,654	0.000339	0.000009	6,654	0.000322	0.000043	6,654	0.000330	0.000031
14	Host Hotels & Resorts, Inc	HST	4.7%	NMF	5.00%	0.50%	12,787	0.000606	0.000028	-	-	-	12,787	0.000618	0.000031	12,787	0.000635	0.000003
15	Xerox Corporation	XRX	3.3%	9.08%	n/a	9.50%	6,668	0.000316	0.000010	6,668	0.000340	0.000031	-	-	-	6,668	0.000331	0.000031
16	Campbell Soup Company	CPB	3.0%	NMF	6.01%	0.50%	14,030	0.000665	0.000020	-	-	-	14,030	0.000678	0.000041	14,030	0.000697	0.000003
17	Archer Daniels Midland Company	ADM	3.4%	NMF	n/a	9.50%	22,822	0.001082	0.000037	-	-	-	-	-	-	22,822	0.001133	0.000108
18	Entergy Corporation	ETR	3.2%	NMF	7.00%	0.50%	22,865	0.001084	0.000035	-	-	-	22,865	0.001105	0.000077	22,865	0.001136	0.000006
19	DXC Technology Company	DXC	2.6%	6.69%	3.91%	10.00%	8,432	0.000400	0.000010	8,432	0.000430	0.000029	8,432	0.000408	0.000016	8,432	0.000419	0.000042
20	Western Digital Corporation	WDC	3.2%	NMF	2.00%	1.00%	18,482	0.000876	0.000028	-	-	-	18,482	0.000894	0.000018	18,482	0.000918	0.000009
21	WestRock Company	WRK	5.1%	NMF	4.52%	10.00%	9,235	0.000438	0.000022	-	-	-	9,235	0.000447	0.000020	9,235	0.000459	0.000046
22	Mid-America Apartment Communities, Inc	MAA	3.0%	7.00%	3.90%	1.00%	14,779	0.000700	0.000021	14,779	0.000753	0.000053	14,779	0.000715	0.000028	14,779	0.000734	0.000007
23	Phillips 66	PSX	3.7%	NMF	6.50%	10.00%	46,236	0.002191	0.000081	-	-	-	46,236	0.002236	0.000145	46,236	0.002296	0.000230
24	CenturyLink, Inc	CTL	7.8%	10.70%	10.67%	1.00%	13,965	0.000662	0.000052	13,965	0.000712	0.000076	13,965	0.000675	0.000072	13,965	0.000694	0.000007
25	Fortive Corporation	FTV	0.4%	10.09%	7.49%	10.00%	23,072	0.001093	0.000004	23,072	0.001176	0.000119	23,072	0.001116	0.000084	23,072	0.001146	0.000115
26	International Business Machines Corporation	IBM	4.6%	2.19%	5.00%	1.50%	126,654	0.006002	0.000274	126,654	0.006453	0.000141	126,654	0.006124	0.000306	126,654	0.006290	0.000094
27	SunTrust Banks, Inc	STI	3.3%	2.60%	8.00%	10.00%	30,231	0.001433	0.000047	30,231	0.001540	0.000040	30,231	0.001462	0.000117	30,231	0.001501	0.000150
28	PPL Corporation	PPL	5.3%	0.59%	n/a	1.50%	22,767	0.001079	0.000057	22,767	0.001160	0.000007	-	-	-	22,767	0.001131	0.000017
29	Morgan Stanley	MS	3.2%	7.63%	8.17%	10.00%	73,021	0.003460	0.000110	73,021	0.003720	0.000284	73,021	0.003531	0.000288	73,021	0.003626	0.000363
30	Perrigo Company plc	PRGO	1.6%	1.70%	2.50%	2.00%	7,388	0.000350	0.000005	7,388	0.000376	0.000006	7,388	0.000357	0.000009	7,388	0.000367	0.000007
31	T Rowe Price Group, Inc	TROW	2.7%	3.18%	8.52%	10.00%	27,320	0.001295	0.000035	27,320	0.001392	0.000044	27,320	0.001321	0.000113	27,320	0.001357	0.000136
32	The Kraft Heinz Company	KHC	5.8%	NMF	4.51%	2.00%	34,343	0.001628	0.000095	-	-	-	34,343	0.001661	0.000075	34,343	0.001706	0.000034
33	eBay Inc	EBAY	1.4%	13.07%	9.37%	10.00%	34,017	0.001612	0.000023	34,017	0.001733	0.000227	34,017	0.001645	0.000154	34,017	0.001689	0.000169
34	Johnson Controls International plc	JCI	2.4%	NMF	9.67%	2.00%	35,035	0.001660	0.000039	-	-	-	35,035	0.001694	0.000164	35,035	0.001740	0.000035
35	Carnival Corporation	CCL	4.1%	8.95%	9.69%	10.00%	25,496	0.001208	0.000050	25,496	0.001299	0.000116	25,496	0.001233	0.000119	25,496	0.001266	0.000127
36	AvalonBay Communities, Inc	AVB	3.0%	2.54%	5.82%	2.50%	29,192	0.001383	0.000041	29,192	0.001487	0.000038	29,192	0.001412	0.000082	29,192	0.001450	0.000036
37	Oracle Corporation	ORCL	1.8%	9.93%	9.60%	10.00%	175,908	0.008336	0.000150	175,908	0.008963	0.000890	175,908	0.008506	0.000834	175,908	0.008736	0.000874
38	General Electric Company	GE	0.4%	10.07%	7.25%	2.50%	82,209	0.003896	0.000017	82,209	0.004189	0.000422	82,209	0.003975	0.000288	82,209	0.004083	0.000102
39	Affiliated Managers Group, Inc	AMG	1.6%	NMF	10.00%	10.00%	4,358	0.000207	0.000003	-	-	-	4,358	0.000211	0.000021	4,358	0.000216	0.000022
40	General Motors Company	GM	4.1%	NMF	10.85%	2.50%	53,940	0.002556	0.000106	-	-	-	53,940	0.002608	0.000283	53,940	0.002679	0.000067
41	Chubb Limited	CB	1.9%	7.71%	10.00%	10.00%	72,288	0.003426	0.000065	72,288	0.003683	0.000284	72,288	0.003495	0.000350	72,288	0.003590	0.000359
42	Newmont Mining Corporation	NEM	1.4%	8.77%	n/a	2.50%	32,296	0.001531	0.000022	32,296	0.001645	0.000144	-	-	-	32,296	0.001604	0.000040
43	Verisk Analytics, Inc	VRSK	0.6%	8.95%	10.14%	10.00%	26,007	0.001232	0.000008	26,007	0.001325	0.000119	26,007	0.001258	0.000128	26,007	0.001292	0.000129
44	Macerich Company (The)	MAC	9.5%	0.21%	1.86%	3.00%	4,566	0.000216	0.000020	4,566	0.000233	0.000000	4,566	0.000221	0.000004	4,566	0.000227	0.000007
45	American Express Company	AXP	1.5%	10.05%	10.18%	10.00%	98,001	0.004644	0.000068	98,001	0.004993	0.000502	98,001	0.004739	0.000482	98,001	0.004867	0.000487
46	Consolidated Edison Inc	ED	3.3%	3.45%	2.00%	3.00%	30,504	0.001446	0.000048	30,504	0.001554	0.000054	30,504	0.001475	0.000029	30,504	0.001515	0.000045
47	Analog Devices, Inc	ADI	1.9%	9.34%	10.50%	10.00%	42,807	0.002029	0.000038	42,807	0.002181	0.000204	42,807	0.002070	0.000217	42,807	0.002126	0.000213
48	Federal Realty Investment Trust	FRT	3.1%	6.70%	4.84%	3.00%	10,044	0.000476	0.000015	10,044	0.000512	0.000034	10,044	0.000486	0.000024	10,044	0.000499	0.000015
49	Raytheon Company	RTN	1.9%	12.27%	10.68%	10.00%	55,414	0.002626	0.000050	55,414	0.002823	0.000346	55,414	0.002679	0.000286	55,414	0.002752	0.000275
50	CME Group Inc	CME	1.4%	5.35%	6.96%	3.00%	75,697	0.003587	0.000051	75,697	0.003857	0.000206	75,697	0.003660	0.000255	75,697	0.003759	0.000113
51	Abbott Laboratories	ABT	1.5%	11.81%	10.97%	10.00%	147,101	0.006971	0.000107	147,101	0.007495	0.000885	147,101	0.007113	0.000780	147,101	0.007305	0.000731
52	Southern Company (The)	SO	4.1%	1.37%	4.50%	3.50%	63,822	0.003025	0.000125	63,822	0.003252	0.000045	63,822	0.003086	0.000139	63,822	0.003170	0.000111
53	NetApp, Inc	NTAP	3.5%	7.23%	11.90%	10.00%	13,009	0.000616	0.000022	13,009	0.000663	0.000048	13,009	0.000629	0.000075	13,009	0.000646	0.000065
54	Allergan plc	AGN	1.6%	3.70%	5.06%	3.50%	54,343	0.002575	0.000046	54,343	0.002769	0.000102	54,343	0.002628	0.000133	54,343	0.002699	0.000094
55	Aon plc	AON	0.9%	11.70%	11.90%	10.00%	45,778	0.002169	0.000020	45,778	0.002332	0.000273	45,778	0.002214	0.000263	45,778	0.002273	0.000227
56	Ford Motor Company	F	6.6%	3.79%	7.30%	3.50%	36,308	0.001721	0.000113	36,308	0.001850	0.000070	36,308	0.001756	0.000128	36,308	0.001803	0.000063
57	Becton, Dickinson and Company	BDX	1.2%	9.93%	12.09%	10.00%	69,211	0.003280	0.000040	69,211	0.003526	0.000350	69,211	0.003347	0.000405	69,211	0.003437	0.000344
58	Macy's Inc	M	9.6%	NMF	7.50%	3.50%	4,856	0.000230	0.000022	-	-	-	4,856	0.000235	0.000018	4,856	0.000241	0.000008
59	Citigroup Inc	C	2.9%	14.64%	12.20%	10.00%	157,524	0.007465	0.000219	157,524	0.008026	0.001175	157,524	0.007617	0.000929	157,524	0.007823	0.000782
60	Seagate Technology PLC	STX	4.8%	7.74%	1.21%	4.00%	14,246	0.000675	0.000032	14,246	0.000726	0.000056	14,246	0.000689	0.000008	14,246	0.000707	0.000028
61	Ecolab Inc	ECL	0.9%	13.55%	12.46%	10.00%	56,543	0.002680	0.000025	56,543	0.002881	0.000390	56,543	0.002734	0.000341	56,543	0.002808	0.000281
62	Ventas, Inc	VTR	4.5%	6.90%	3.01%	4.00%	25,769	0.001221	0.000055	25,769	0.001313	0.000091	25,769	0.001246	0.000038	25,769	0.001280	0.000051
63	Thermo Fisher Scientific Inc	TMO	0.3%	11.37%	12.50%	10.00%	118,241	0.005603	0.000015	118,241	0.006024	0.000685	118,241	0.005717	0.000715	118,241	0.005872	0.000587
64	Verizon Communications Inc	VZ	4.1%	2.86%	4.17%	4.00%	248,063	0.011756	0.000482	248,063	0.012639	0.000361	248,063	0.011995	0.000500	248,063	0.012319	0.000493
65	J B Hunt Transport Services, Inc	JBHT	1.0%	9.08%	15.00%	10.00%	12,075	0.000572	0.000005	12,075	0.000615	0.000056	12,075	0.000584	0.000088	12,075	0.000600	0.000060
66	Hanesbrands Inc	HBI	4.1%	3.06%	4.36%	4.00%	5,239	0.000248	0.000010	5,239	0.000267	0.000008	5,239	0.000253	0.000011	5,239	0.000260	0.000010
67	Delta Air Lines, Inc	DAL	2.7%	14.07%	16.96%	10.00%	38,160	0.001808	0.000050	38,160	0.001944	0.000274	38,160	0.001845	0.000313	38,160	0.001895	0.000190
68	Kellogg Company	K	3.6%	0.75%	4.50%	4.00%	21,735	0.001030	0.000037	21,735	0.001107	0.000008	21,735	0.001051	0.000047	21,735	0.001079	0.000043
69	Raymond James Financial, Inc	RJF	1.6%	9.00%	n/a	10.00%	11,894	0.000564	0.000009	11,894	0.000606	0.000055	-	-	-	11,894	0.000591	0.000059
70	Extra Space Storage Inc	EXR	3.1%	6.00%	4.79%	4.00%	14,852	0.000704	0.000022	14,852	0.000757	0.000045	14,852	0.000718	0.000034	14,852	0.000738	0.000030
71	KeyCorp	KEY	4.1%	4.57%	3.26%	10.50%	18,106	0.000858	0.000035	18,106	0.000923	0.000042	18,106	0.000876	0.000029	18,106	0.000899	0.000094
72	American Electric Power Company, Inc	AEP	3.1%	6.10%	5.66%	4.00%	46,008	0.002180	0.000067	46,008	0.002344	0.000143	46,008	0.002225	0.000126	46,008	0.002285	0.000091
73	Welltower Inc	WELL	4.0%	13.00%	4.64%	10.50%	32,380	0.001535	0.000061	32,380	0.001650	0.000214	32,380	0.001566	0.000073	32,380	0.001608	0.000169
74	Newell Brands Inc	NWL	5.2%	NMF	6.00%	4.00%	7,566	0.000359	0.000018	-	-	-	7,566	0.000366	0.000022	7,566	0.000376	0.000015
75	International Paper Company	IP	4.9%	NMF	5.00%	10.50%	16,055	0.000761	0.000037	-	-	-	16,055	0.000776	0.000039	16,055	0.000797	0.000084
76	General Mills, Inc	GIS	3.6%	6.58%	7.00%	4.00%	32,857	0.001557	0.000057	32,857	0.001674	0.000110	32,857	0.001589	0.000111	32,857	0.001632	0.000065
77	AbbVie Inc	ABBV	6.0%	4.55%	5.50%	10.50%	105,955	0.005021	0.000300	105,955	0.005398	0.000246	105,955	0.005123	0.000282	105,955	0.005262	0.000553
78	Realty Income Corporation	O	3.7%	6.40%	3.87%	4.50%	22,969	0.001089	0.000041	22,969	0.001170	0.000075	22,969	0.001111	0.000043	22,969	0.001141	0.000051
79	Cardinal Health, Inc	CAH	4.0%	3.05%	6.03%	10.50%	14,310	0.000678	0.000027	14,310	0.000729	0.000022	14,310	0.000692	0.000042	14,310	0.000711	0.000075
80	Public Storage	PSA	3.3%	17.00%	4.01%	4.50%	43,601	0.002066	0.000068	43,601	0.002221	0.000378	43,601	0.002108	0.000085	43,601	0.002165	0.000097
81	First Republic Bank	FRC	0.8%	11.30%	6.99%	10.50%	16,036	0.000760	0.000006	16,036	0.000817	0.000092	16,036	0.000775	0.000054	16,036	0.000796	0.000084
82	Simon Property Group, Inc	SPG	5.6%	8.60%	4.39%	4.50%	47,779	0.002264	0.000127	47,779	0.002434	0.000209	47,779	0.002310	0.000101	47,779	0.002373	0.000107
83	Regions Financial Corporation	RF	3.9%	9.64%	7.01%	10.50%	16,182	0.000767	0.000030	16,182	0.000824	0.000079	16,182	0.000782	0.000055	16,182	0.000804	0.000084
84	Duke Realty Corporation	DRE	2.7%	6.00%	4.49%	4.50%	11,971	0.000567	0.000015	11,971	0.000610	0.000037	11,971	0.000579	0.000026	11,971	0.000595	0.000027
85	Garmin Ltd	GRMN	2.7%	5.50%	7.35%	10.50%	16,252	0.000770	0.000021	16,252	0.000826	0.000046	16,252	0.000786	0.000058	16,252	0.000807	0.000085
86	The Western Union Company	WU	3.5%	2.27%	5.00%	4.50%	9,672	0.000458	0.000016	9,672	0.000493	0.000011	9,672	0.000468	0.000023	9,672	0.000480	0.000022
87	Intel Corporation	INTC	2.4%	7.33%	7.50%	10.50%	228,455	0.010827	0.000264	228,455	0.011640	0.000853	228,455	0.011047	0.000828	228,455	0.011346	0.001191
88	The Kroger Co	KR	2.5%	4.88%	6.34%	4.50%	20,630	0.000978	0.000024	20,630	0.001051	0.000051	20,630	0.000998	0.000063	20,630	0.001025	0.000046
89	Motorola Solutions, Inc	MSI	1.5%	10.31%	7.65%	10.50%	27,641	0.001310	0.000019	27,641	0.001408	0.000145	27,641	0.001337	0.000102	27,641	0.001373	0.000144
90	Zimmer Biomet Holdings, Inc	ZBH	0.7%	5.68%	6.74%	4.50%	28,616	0.001356	0.000009	28,616	0.001458	0.000086	28,616	0.001384	0.000093	28,616	0.001421	0.000064
91	NextEra Energy, Inc	NEE	2.4%	7.99%	8.01%	10.50%	107,727	0.005105	0.000121	107,727	0.005489	0.000439	107,727	0.005209	0.000417	107,727	0.005350	0.000562
92	Conagra Brands Inc	CAG	2.9%	9.23%	7.00%	4.50%	14,412	0.000683	0.000020	14,412	0.000734	0.000068	14,412	0.000697	0.000049	14,412	0.000716	0.000032
93	Intercontinental Exchange Inc	ICE	1.2%	8.64%	8.05%	10.50%	52,470	0.002487	0.000029	52,470	0.002673	0.000231	52,470	0.002537	0.000204	52,470	0.002606	0.000274
94	BorgWarner Inc	BWA	1.8%	2.34%	7.75%	4.50%	7,647	0.000362	0.000007	7,647	0.000390	0.000009	7,647	0.000370	0.000029	7,647	0.000380	0.000017
95	The Allstate Corporation	ALL	1.9%	10.40%	8.33%	10.50%	32,508	0.001541	0.000029	32,508	0.001656	0.000172	32,508	0.001572	0.000131	32,508	0.001614	0.000170
96	DENTSPLY SIRONA Inc	XRAY	0.7%	12.82%	11.62%	4.50%	11,183	0.000530	0.000004	11,183	0.000570	0.000073	11,183	0.000541	0.000063	11,183	0.000555	0.000025
97	Bank of America Corporation	BAC	2.4%	8.77%	9.00%	10.50%	278,596	0.013203	0.000318	278,596	0.014195	0.001245	278,596	0.013471	0.001212	278,596	0.013836	0.001453
98	The J M Smucker Company	SJM	3.3%	3.30%	3.71%	5.00%	12,276	0.000582	0.000019	12,276	0.000625	0.000021	12,276	0.000594	0.000022	12,276	0.000610	0.000030
99	Paychex, Inc	PAYX	3.2%	9.09%	9.00%	10.50%	29,651	0.001405	0.000044	29,651	0.001511	0.000137	29,651	0.001434	0.000129	29,651	0.001473	0.000155
100	Kimco Realty Corporation	KIM	5.6%	4.60%	3.79%	5.00%	8,520	0.000404	0.000023	8,520	0.000434	0.000020	8,520	0.000412	0.000016	8,520	0.000423	0.000021
101	Fortune Brands Home & Security, Inc	FBHS	1.7%	7.75%	9.11%	10.50%	7,429	0.000352	0.000006	7,429	0.000379	0.000029	7,429	0.000359	0.000033	7,429	0.000369	0.000039
102	The Clorox Company	CLX	2.6%	3.69%	4.96%	5.00%	19,382	0.000919	0.000025	19,382	0.000988	0.000036	19,382	0.000937	0.000046	19,382	0.000963	0.000048
103	Marathon Petroleum Corporation	MPC	3.9%	8.18%	9.95%	10.50%	35,587	0.001686	0.000066	35,587	0.001813	0.000148	35,587	0.001721	0.000171	35,587	0.001767	0.000186
104	Boston Properties, Inc	BXP	3.0%	7.00%	6.24%	5.00%	20,084	0.000952	0.000029	20,084	0.001023	0.000072	20,084	0.000971	0.000061	20,084	0.000997	0.000050
105	Southwest Airlines Co	LUV	1.3%	12.48%	9.98%	10.50%	29,606	0.001403	0.000018	29,606	0.001508	0.000188	29,606	0.001432	0.000143	29,606	0.001470	0.000154
106	Coty Inc	COTY	4.9%	3.00%	6.65%	5.00%	7,717	0.000366	0.000018	7,717	0.000393	0.000012	7,717	0.000373	0.000025	7,717	0.000383	0.000019
107	Microchip Technology Incorporated	MCHP	1.6%	5.40%	10.49%	10.50%	22,016	0.001043	0.000017	22,016	0.001122	0.000061	22,016	0.001065	0.000112	22,016	0.001093	0.000115
108	The Gap, Inc	GPS	5.5%	3.96%	9.00%	5.00%	6,595	0.000313	0.000017	6,595	0.000336	0.000013	6,595	0.000319	0.000029	6,595	0.000328	0.000016
109	Tiffany & Co	TIF	2.6%	8.53%	11.00%	10.50%	11,034	0.000523	0.000013	11,034	0.000562	0.000048	11,034	0.000534	0.000059	11,034	0.000548	0.000058
110	State Street Corporation	STT	3.4%	NMF	10.67%	5.00%	22,764	0.001079	0.000037	-	-	-	22,764	0.001101	0.000117	22,764	0.001131	0.000057
111	Dover Corporation	DOV	2.0%	10.40%	11.50%	10.50%	14,394	0.000682	0.000014	14,394	0.000733	0.000076	14,394	0.000696	0.000080	14,394	0.000715	0.000075
112	SL Green Realty Corporation	SLG	4.3%	NMF	3.46%	5.50%	6,926	0.000328	0.000014	-	-	-	6,926	0.000335	0.000012	6,926	0.000344	0.000019
113	Jack Henry & Associates, Inc	JKHY	1.1%	12.00%	11.50%	10.50%	11,388	0.000540	0.000006	11,388	0.000580	0.000070	11,388	0.000551	0.000063	11,388	0.000566	0.000059
114	AT&T Inc	T	5.6%	3.40%	4.45%	5.50%	271,382	0.012861	0.000716	271,382	0.013827	0.000470	271,382	0.013122	0.000584	271,382	0.013477	0.000741
115	The Sherwin-Williams Company	SHW	0.9%	14.22%	12.07%	10.50%	50,721	0.002404	0.000022	50,721	0.002584	0.000367	50,721	0.002453	0.000296	50,721	0.002519	0.000264
116	Xcel Energy Inc	XEL	2.6%	5.80%	4.92%	5.50%	33,085	0.001568	0.000041	33,085	0.001686	0.000098	33,085	0.001600	0.000079	33,085	0.001643	0.000090
117	QUALCOMM Incorporated	QCOM	3.2%	NMF	12.77%	10.50%	95,284	0.004516	0.000143	-	-	-	95,284	0.004607	0.000588	95,284	0.004732	0.000497
118	Molson Coors Brewing Company	TAP	4.1%	NMF	5.45%	5.50%	11,762	0.000557	0.000023	-	-	-	11,762	0.000569	0.000031	11,762	0.000584	0.000032
119	Baxter International Inc	BAX	1.0%	10.73%	12.80%	10.50%	44,624	0.002115	0.000021	44,624	0.002274	0.000244	44,624	0.002158	0.000276	44,624	0.002216	0.000233

	Company	Ticker	Dividend Yield	EPS Growth Rates IBES	EPS Growth Rates Zacks	EPS Growth Rates Value Line	Market Cap ($Millions)	Weighted Dividend Yield Weight	Weighted Dividend Yield Product	Mkt. Cap.	Weighted IBES Weight	Product	Mkt. Cap.	Weighted Zacks Weight	Product	Mkt. Cap.	Weighted Value Line Weight	Product
	(a)		(b)	(c)	(d)	(b)	(b)											
120	Eversource Energy	ES	2.6%	5.63%	5.64%	5.50%	26,931	0.001276	0.000034	26,931	0.001372	0.000077	26,931	0.001302	0.000073	26,931	0.001337	0.000074
121	Pfizer Inc.	PFE	3.9%	4.73%	4.47%	11.00%	203,069	0.009624	0.000379	203,069	0.010346	0.000489	203,069	0.009819	0.000439	203,069	0.010085	0.001109
122	DTE Energy Company	DTE	3.1%	4.45%	6.00%	5.50%	24,172	0.001146	0.000035	24,172	0.001232	0.000055	24,172	0.001169	0.000070	24,172	0.001200	0.000066
123	Interpublic Group of Companies, Inc. (The)	IPG	4.7%	6.20%	4.70%	11.00%	8,238	0.000390	0.000018	8,238	0.000420	0.000026	8,238	0.000398	0.000019	8,238	0.000409	0.000045
124	Pinnacle West Capital Corporation	PNW	3.2%	5.05%	6.09%	5.50%	10,810	0.000512	0.000016	10,810	0.000551	0.000028	10,810	0.000523	0.000032	10,810	0.000537	0.000030
125	Sempra Energy	SRE	2.9%	10.10%	7.77%	11.00%	38,582	0.001828	0.000052	38,582	0.001966	0.000199	38,582	0.001866	0.000145	38,582	0.001916	0.000211
126	United Dominion Realty Trust, Inc.	UDR	2.8%	NMF	6.21%	5.50%	13,290	0.000630	0.000018	–	–	–	13,290	0.000643	0.000040	13,290	0.000660	0.000036
127	Universal Health Services, Inc.	UHS	0.5%	8.67%	8.07%	11.00%	13,274	0.000629	0.000003	13,274	0.000676	0.000059	13,274	0.000642	0.000052	13,274	0.000659	0.000073
128	Principal Financial Group, Inc.	PFG	3.9%	6.76%	6.67%	5.50%	15,852	0.000751	0.000029	15,852	0.000808	0.000055	15,852	0.000767	0.000053	15,852	0.000787	0.000043
129	Avery Dennison Corporation	AVY	2.1%	10.52%	8.25%	11.00%	9,608	0.000455	0.000010	9,608	0.000490	0.000051	9,608	0.000465	0.000038	9,608	0.000477	0.000052
130	LyondellBasell Industries N.V.	LYB	4.7%	3.63%	9.00%	5.50%	32,813	0.001555	0.000074	32,813	0.001672	0.000061	32,813	0.001587	0.000143	32,813	0.001630	0.000090
131	Darden Restaurants, Inc.	DRI	3.0%	8.63%	8.87%	11.00%	14,856	0.000704	0.000021	14,856	0.000757	0.000065	14,856	0.000718	0.000064	14,856	0.000738	0.000081
132	Wells Fargo & Company	WFC	4.2%	8.02%	10.70%	5.50%	216,162	0.010244	0.000427	216,162	0.011014	0.000883	216,162	0.010452	0.001118	216,162	0.010735	0.000590
133	S&P Global Inc.	SPGI	1.0%	8.80%	10.00%	11.00%	63,233	0.002997	0.000028	63,233	0.003222	0.000284	63,233	0.003058	0.000306	63,233	0.003140	0.000345
134	Albemarle Corporation	ALB	2.2%	11.10%	12.38%	5.50%	7,237	0.000343	0.000007	7,237	0.000369	0.000041	7,237	0.000350	0.000043	7,237	0.000359	0.000020
135	Broadridge Financial Solutions, Inc.	BR	1.7%	10.00%	10.00%	11.00%	14,692	0.000696	0.000012	14,692	0.000749	0.000075	14,692	0.000710	0.000071	14,692	0.000730	0.000080
136	Alaska Air Group, Inc.	ALK	2.2%	NMF	NMF	5.50%	7,965	0.000377	0.000008	–	–	–	–	–	–	7,965	0.000396	0.000022
137	Moody's Corporation	MCO	0.9%	11.00%	10.00%	11.00%	40,967	0.001941	0.000018	40,967	0.002087	0.000230	40,967	0.001981	0.000198	40,967	0.002035	0.000224
138	Public Service Enterprise Group Incorporated	PEG	3.1%	3.65%	3.13%	6.00%	31,107	0.001474	0.000046	31,107	0.001585	0.000058	31,107	0.001504	0.000047	31,107	0.001545	0.000093
139	Aptiv PLC	APTV	1.0%	9.71%	11.13%	11.00%	22,922	0.001086	0.000011	22,922	0.001168	0.000113	22,922	0.001108	0.000123	22,922	0.001138	0.000125
140	Duke Energy Corporation	DUK	4.0%	4.06%	4.86%	6.00%	68,789	0.003260	0.000131	68,789	0.003505	0.000142	68,789	0.003326	0.000162	68,789	0.003416	0.000205
141	PerkinElmer, Inc.	PKI	0.3%	14.63%	13.39%	11.00%	9,563	0.000453	0.000001	9,563	0.000487	0.000071	9,563	0.000462	0.000062	9,563	0.000475	0.000052
142	Packaging Corporation of America	PKG	3.1%	1.16%	5.00%	6.00%	9,785	0.000464	0.000014	9,785	0.000499	0.000006	9,785	0.000473	0.000024	9,785	0.000486	0.000029
143	Comerica Incorporated	CMA	4.1%	3.60%	14.20%	11.00%	9,887	0.000469	0.000019	9,887	0.000504	0.000018	9,887	0.000478	0.000068	9,887	0.000491	0.000054
144	Pentair plc	PNR	1.9%	6.90%	5.11%	6.00%	6,322	0.000300	0.000006	6,322	0.000322	0.000022	6,322	0.000306	0.000016	6,322	0.000314	0.000019
145	Huntington Bancshares Incorporated	HBAN	4.2%	5.98%	7.04%	11.50%	15,018	0.000712	0.000030	15,018	0.000765	0.000046	15,018	0.000726	0.000051	15,018	0.000746	0.000086
146	Colgate-Palmolive Company	CL	2.4%	1.81%	5.47%	6.00%	60,876	0.002885	0.000070	60,876	0.003102	0.000056	60,876	0.002944	0.000161	60,876	0.003023	0.000181
147	Lockheed Martin Corporation	LMT	2.3%	14.47%	7.10%	11.50%	111,104	0.005265	0.000123	111,104	0.005661	0.000819	111,104	0.005372	0.000381	111,104	0.005518	0.000635
148	Nordstrom, Inc.	JWN	4.6%	3.68%	6.00%	6.00%	4,980	0.000236	0.000011	4,980	0.000254	0.000009	4,980	0.000241	0.000014	4,980	0.000247	0.000015
149	Marriott International	MAR	1.5%	7.10%	7.40%	11.50%	42,668	0.002022	0.000030	42,668	0.002174	0.000154	42,668	0.002063	0.000153	42,668	0.002119	0.000244
150	U.S. Bancorp	USB	3.1%	5.82%	6.00%	6.00%	88,415	0.004190	0.000128	88,415	0.004505	0.000262	88,415	0.004275	0.000257	88,415	0.004391	0.000263
151	Valero Energy Corporation	VLO	4.4%	4.39%	8.00%	11.50%	34,641	0.001642	0.000073	34,641	0.001765	0.000077	34,641	0.001675	0.000134	34,641	0.001720	0.000198
152	WEC Energy Group, Inc.	WEC	2.6%	6.12%	6.16%	6.00%	29,487	0.001397	0.000037	29,487	0.001502	0.000092	29,487	0.001426	0.000088	29,487	0.001464	0.000088
153	Emerson Electric Co.	EMR	3.1%	6.02%	8.06%	11.50%	40,086	0.001900	0.000058	40,086	0.002042	0.000123	40,086	0.001938	0.000156	40,086	0.001991	0.000229
154	Juniper Networks, Inc.	JNPR	3.3%	2.07%	6.31%	6.00%	8,223	0.000390	0.000013	8,223	0.000419	0.000009	8,223	0.000398	0.000025	8,223	0.000408	0.000025
155	Republic Services, Inc.	RSG	1.9%	9.05%	9.03%	11.50%	30,372	0.001439	0.000027	30,372	0.001547	0.000140	30,372	0.001469	0.000133	30,372	0.001508	0.000173
156	Viacom Inc.	VIAB	3.2%	2.92%	6.91%	6.00%	10,177	0.000482	0.000015	10,177	0.000519	0.000015	10,177	0.000492	0.000034	10,177	0.000505	0.000030
157	Parker-Hannifin Corporation	PH	2.0%	7.17%	9.14%	11.50%	22,818	0.001081	0.000021	22,818	0.001163	0.000083	22,818	0.001103	0.000101	22,818	0.001133	0.000130
158	Capital One Financial Corporation	COF	1.7%	6.10%	7.00%	6.00%	43,868	0.002079	0.000036	43,868	0.002235	0.000136	43,868	0.002121	0.000148	43,868	0.002179	0.000131
159	NVIDIA Corporation	NVDA	0.4%	12.50%	9.56%	11.50%	107,757	0.005107	0.000018	107,757	0.005490	0.000686	107,757	0.005210	0.000498	107,757	0.005351	0.000615
160	Philip Morris International Inc.	PM	6.5%	5.71%	7.86%	6.00%	111,568	0.005287	0.000345	111,568	0.005684	0.000325	111,568	0.005395	0.000424	111,568	0.005541	0.000332
161	Eli Lilly and Company	LLY	2.3%	9.40%	10.07%	11.50%	110,397	0.005232	0.000118	110,397	0.005625	0.000529	110,397	0.005338	0.000538	110,397	0.005483	0.000630
162	Skyworks Solutions, Inc.	SWKS	2.2%	15.00%	8.19%	6.00%	13,603	0.000645	0.000014	13,603	0.000693	0.000104	13,603	0.000658	0.000054	13,603	0.000676	0.000041
163	Roper Technologies, Inc.	ROP	0.5%	7.10%	11.00%	11.50%	37,080	0.001757	0.000009	37,080	0.001889	0.000134	37,080	0.001793	0.000197	37,080	0.001841	0.000212
164	Invesco Ltd.	IVZ	7.3%	2.28%	8.35%	6.00%	8,010	0.000380	0.000028	8,010	0.000408	0.000009	8,010	0.000387	0.000032	8,010	0.000398	0.000024
165	Tractor Supply Company	TSCO	1.6%	11.47%	11.05%	11.50%	11,024	0.000522	0.000008	11,024	0.000562	0.000064	11,024	0.000533	0.000059	11,024	0.000547	0.000063
166	Snap-On Incorporated	SNA	2.7%	7.25%	8.71%	6.00%	8,565	0.000406	0.000011	8,565	0.000436	0.000032	8,565	0.000414	0.000036	8,565	0.000425	0.000026
167	Humana Inc.	HUM	0.8%	13.19%	13.14%	11.50%	37,610	0.001782	0.000014	37,610	0.001916	0.000253	37,610	0.001819	0.000239	37,610	0.001868	0.000215
168	General Dynamics Corporation	GD	2.2%	8.79%	8.72%	6.00%	54,340	0.002575	0.000056	54,340	0.002769	0.000243	54,340	0.002628	0.000229	54,340	0.002699	0.000162
169	KLA-Tencor Corporation	KLAC	2.2%	14.57%	13.28%	11.50%	25,410	0.001204	0.000026	25,410	0.001295	0.000189	25,410	0.001229	0.000163	25,410	0.001262	0.000145
170	Cognizant Technology Solutions Corporation	CTSH	1.3%	5.86%	11.00%	6.00%	35,035	0.001660	0.000021	35,035	0.001785	0.000105	35,035	0.001694	0.000186	35,035	0.001740	0.000104
171	Lowe's Companies, Inc.	LOW	2.0%	14.82%	13.46%	11.50%	86,811	0.004114	0.000081	86,811	0.004423	0.000655	86,811	0.004198	0.000565	86,811	0.004311	0.000496
172	Maxim Integrated Products, Inc.	MXIM	3.3%	7.66%	11.67%	6.00%	15,931	0.000755	0.000025	15,931	0.000812	0.000062	15,931	0.000770	0.000090	15,931	0.000791	0.000047
173	The Charles Schwab Corporation	SCHW	1.6%	4.05%	5.67%	12.00%	56,161	0.002662	0.000042	56,161	0.002861	0.000116	56,161	0.002716	0.000154	56,161	0.002789	0.000335
174	Dominion Energy Inc.	D	4.6%	4.59%	4.84%	6.50%	64,979	0.003079	0.000142	64,979	0.003311	0.000152	64,979	0.003142	0.000152	64,979	0.003227	0.000210
175	Johnson & Johnson	JNJ	2.9%	6.46%	6.87%	12.00%	343,759	0.016291	0.000476	343,759	0.017515	0.001131	343,759	0.016622	0.001142	343,759	0.017072	0.002049
176	The Walt Disney Company	DIS	1.3%	NMF	5.04%	6.50%	237,407	0.011251	0.000149	–	–	–	237,407	0.011480	0.000579	237,407	0.011790	0.000766
177	Tapestry, Inc.	TPR	5.3%	4.33%	9.30%	12.00%	7,331	0.000347	0.000019	7,331	0.000374	0.000016	7,331	0.000354	0.000033	7,331	0.000364	0.000044
178	Omnicom Group Inc.	OMC	3.4%	4.70%	5.07%	6.50%	17,076	0.000809	0.000028	17,076	0.000870	0.000041	17,076	0.000826	0.000042	17,076	0.000848	0.000055
179	Sysco Corporation	SYY	2.0%	10.55%	9.46%	12.00%	40,204	0.001905	0.000038	40,204	0.002048	0.000216	40,204	0.001944	0.000184	40,204	0.001997	0.000240
180	Whirlpool Corporation	WHR	3.2%	4.60%	5.26%	6.50%	9,360	0.000444	0.000014	9,360	0.000477	0.000022	9,360	0.000453	0.000024	9,360	0.000465	0.000030
181	Dollar General Corporation	DG	0.8%	10.48%	10.21%	12.00%	40,311	0.001910	0.000016	40,311	0.002054	0.000215	40,311	0.001949	0.000199	40,311	0.002002	0.000240
182	Alliant Energy Corporation	LNT	2.7%	5.05%	5.54%	6.50%	12,615	0.000598	0.000016	12,615	0.000643	0.000032	12,615	0.000610	0.000034	12,615	0.000626	0.000041
183	Ingersoll-Rand PLC (Ireland)	IR	1.7%	11.14%	10.91%	12.00%	29,948	0.001419	0.000024	29,948	0.001526	0.000170	29,948	0.001448	0.000158	29,948	0.001487	0.000178
184	Prologis, Inc.	PLD	2.6%	NMF	5.67%	6.50%	53,530	0.002537	0.000066	–	–	–	53,530	0.002588	0.000147	53,530	0.002658	0.000173
185	HCA Healthcare, Inc.	HCA	1.3%	10.24%	11.25%	12.00%	43,311	0.002053	0.000026	43,311	0.002207	0.000226	43,311	0.002094	0.000236	43,311	0.002151	0.000258
186	Ameren Corporation	AEE	2.6%	4.70%	6.41%	6.50%	19,335	0.000916	0.000024	19,335	0.000985	0.000046	19,335	0.000935	0.000060	19,335	0.000960	0.000062
187	Yum! Brands, Inc.	YUM	1.5%	14.61%	12.25%	12.00%	34,686	0.001644	0.000025	34,686	0.001767	0.000258	34,686	0.001677	0.000205	34,686	0.001723	0.000207
188	CVS Health Corporation	CVS	3.1%	3.25%	6.58%	6.50%	82,655	0.003917	0.000123	82,655	0.004211	0.000137	82,655	0.003997	0.000263	82,655	0.004105	0.000267
189	Kansas City Southern	KSU	1.1%	14.46%	15.00%	12.00%	13,214	0.000626	0.000007	13,214	0.000673	0.000097	13,214	0.000639	0.000096	13,214	0.000656	0.000079
190	Hewlett Packard Enterprise Company	HPE	3.0%	8.41%	6.60%	6.50%	19,454	0.000922	0.000028	19,454	0.000991	0.000083	19,454	0.000941	0.000062	19,454	0.000966	0.000063
191	FLIR Systems, Inc.	FLIR	1.3%	NMF	n/a	12.00%	7,197	0.000341	0.000005	–	–	–	–	–	–	7,197	0.000357	0.000043
192	Coca-Cola Company (The)	KO	2.9%	5.20%	6.84%	6.50%	233,073	0.011045	0.000325	233,073	0.011875	0.000618	233,073	0.011270	0.000771	233,073	0.011575	0.000752
193	NiSource, Inc.	NI	2.7%	4.66%	5.39%	12.50%	10,988	0.000521	0.000014	10,988	0.000560	0.000026	10,988	0.000531	0.000029	10,988	0.000546	0.000068
194	Pepsico, Inc.	PEP	2.8%	3.67%	6.99%	6.50%	189,537	0.008982	0.000253	189,537	0.009657	0.000354	189,537	0.009165	0.000641	189,537	0.009413	0.000612
195	CenterPoint Energy, Inc.	CNP	3.9%	5.11%	5.46%	12.50%	15,087	0.000715	0.000028	15,087	0.000769	0.000039	15,087	0.000729	0.000040	15,087	0.000749	0.000094
196	Citrix Systems, Inc.	CTXS	1.5%	7.80%	7.31%	6.50%	12,585	0.000596	0.000009	12,585	0.000641	0.000050	12,585	0.000609	0.000044	12,585	0.000625	0.000041
197	Apple Inc.	AAPL	1.4%	9.68%	8.75%	12.50%	1,001,257	0.047450	0.000683	1,001,257	0.051014	0.004938	1,001,257	0.048414	0.004236	1,001,257	0.049725	0.006216
198	Hershey Company (The)	HSY	2.0%	8.70%	7.33%	6.50%	32,172	0.001525	0.000031	32,172	0.001639	0.000143	32,172	0.001556	0.000114	32,172	0.001598	0.000104
199	The Hartford Financial Services Group, Inc.	HIG	2.0%	9.06%	9.50%	12.50%	21,928	0.001039	0.000021	21,928	0.001117	0.000101	21,928	0.001060	0.000101	21,928	0.001089	0.000136
200	Kohl's Corporation	KSS	5.8%	8.00%	10.00%	6.50%	7,765	0.000368	0.000021	7,765	0.000396	0.000032	7,765	0.000375	0.000038	7,765	0.000386	0.000025
201	Royal Caribbean Cruises Ltd.	RCL	2.8%	11.25%	10.55%	12.50%	23,563	0.001117	0.000031	23,563	0.001201	0.000135	23,563	0.001139	0.000120	23,563	0.001170	0.000146
202	Texas Instruments Incorporated	TXN	2.4%	10.00%	10.13%	6.50%	120,400	0.005706	0.000136	120,400	0.006134	0.000613	120,400	0.005822	0.000590	120,400	0.005979	0.000389
203	Crown Castle International Corporation	CCI	3.5%	NMF	15.50%	12.50%	58,756	0.002784	0.000097	–	–	–	58,756	0.002841	0.000440	58,756	0.002918	0.000365
204	Assurant, Inc.	AIZ	1.9%	19.40%	n/a	6.50%	7,726	0.000366	0.000007	7,726	0.000394	0.000076	–	–	–	7,726	0.000384	0.000025
205	Ameriprise Financial, Inc.	AMP	2.6%	18.83%	n/a	12.50%	19,338	0.000916	0.000024	19,338	0.000985	0.000186	–	–	–	19,338	0.000960	0.000120
206	Amgen Inc.	AMGN	3.0%	7.77%	5.38%	7.00%	117,801	0.005583	0.000170	117,801	0.006002	0.000466	117,801	0.005696	0.000306	117,801	0.005850	0.000410
207	Textron Inc.	TXT	0.2%	9.47%	9.93%	13.00%	11,832	0.000561	0.000001	11,832	0.000603	0.000057	11,832	0.000572	0.000057	11,832	0.000588	0.000076
208	Symantec Corporation	SYMC	1.3%	9.50%	5.38%	7.00%	14,796	0.000701	0.000009	14,796	0.000754	0.000072	14,796	0.000715	0.000038	14,796	0.000735	0.000051
209	Stryker Corporation	SYK	0.9%	10.39%	10.04%	13.00%	82,695	0.003919	0.000037	82,695	0.004213	0.000438	82,695	0.003999	0.000401	82,695	0.004107	0.000534
210	Kimberly-Clark Corporation	KMB	3.1%	4.89%	5.50%	7.00%	46,166	0.002188	0.000067	46,166	0.002352	0.000115	46,166	0.002232	0.000123	46,166	0.002293	0.000160
211	Zoetis Inc.	ZTS	0.5%	11.12%	11.10%	13.00%	59,379	0.002814	0.000015	59,379	0.003025	0.000336	59,379	0.002871	0.000319	59,379	0.002949	0.000383
212	CMS Energy Corporation	CMS	2.6%	7.14%	6.40%	7.00%	17,837	0.000845	0.000022	17,837	0.000909	0.000065	17,837	0.000862	0.000055	17,837	0.000886	0.000062
213	Nucor Corporation	NUE	3.0%	NMF	12.00%	13.00%	15,982	0.000757	0.000023	–	–	–	15,982	0.000773	0.000093	15,982	0.000794	0.000103
214	Digital Realty Trust, Inc.	DLR	3.6%	16.66%	6.93%	7.00%	25,562	0.001211	0.000044	25,562	0.001302	0.000217	25,562	0.001236	0.000086	25,562	0.001269	0.000089
215	Caterpillar Inc.	CAT	3.2%	5.09%	12.00%	13.00%	73,204	0.003469	0.000110	73,204	0.003730	0.000190	73,204	0.003540	0.000425	73,204	0.003635	0.000473
216	Fifth Third Bancorp	FITB	3.4%	13.11%	7.17%	7.00%	20,445	0.000969	0.000033	20,445	0.001042	0.000137	20,445	0.000989	0.000071	20,445	0.001015	0.000071
217	Rollins, Inc.	ROL	1.2%	8.20%	n/a	13.00%	11,383	0.000539	0.000007	11,383	0.000580	0.000048	–	–	–	11,383	0.000565	0.000073
218	The Bank of New York Mellon Corporation	BK	2.6%	2.86%	8.25%	7.00%	44,286	0.002099	0.000055	44,286	0.002256	0.000065	44,286	0.002141	0.000177	44,286	0.002199	0.000154
219	The TJX Companies, Inc.	TJX	1.6%	8.51%	10.63%	13.50%	68,256	0.003235	0.000053	68,256	0.003478	0.000296	68,256	0.003300	0.000351	68,256	0.003390	0.000458
220	Prudential Financial, Inc.	PRU	4.5%	7.91%	9.00%	7.00%	35,869	0.001700	0.000076	35,869	0.001828	0.000145	35,869	0.001734	0.000156	35,869	0.001781	0.000125
221	Danaher Corporation	DHR	0.5%	10.19%	11.57%	13.50%	104,547	0.004955	0.000023	104,547	0.005327	0.000543	104,547	0.005055	0.000585	104,547	0.005192	0.000701
222	3M Company	MMM	3.5%	3.41%	9.50%	7.00%	96,112	0.004555	0.000157	96,112	0.004897	0.000167	96,112	0.004647	0.000441	96,112	0.004773	0.000334
223	Comcast Corporation	CMCSA	1.8%	10.21%	11.88%	13.50%	212,160	0.010054	0.000181	212,160	0.010810	0.001104	212,160	0.010259	0.001219	212,160	0.010536	0.001422
224	H&R Block, Inc.	HRB	4.4%	10.00%	10.00%	7.00%	4,773	0.000226	0.000010	4,773	0.000243	0.000024	4,773	0.000231	0.000023	4,773	0.000237	0.000017
225	Westinghouse Air Brake Technologies Corporation	WAB	0.7%	14.00%	12.50%	13.50%	13,880	0.000658	0.000004	13,880	0.000707	0.000099	13,880	0.000671	0.000084	13,880	0.000689	0.000093
226	V.F. Corporation	VFC	2.0%	6.70%	10.12%	7.00%	34,643	0.001642	0.000033	34,643	0.001765	0.000118	34,643	0.001675	0.000170	34,643	0.001720	0.000120
227	UnitedHealth Group Incorporated	UNH	1.9%	13.73%	12.65%	13.50%	220,742	0.010461	0.000195	220,742	0.011247	0.001544	220,742	0.010674	0.001350	220,742	0.010963	0.001480
228	Huntington Ingalls Industries, Inc.	HII	1.6%	NMF	n/a	7.00%	9,044	0.000429	0.000007	–	–	–	–	–	–	9,044	0.000449	0.000031
229	Starbucks Corporation	SBUX	1.8%	13.10%	13.25%	13.50%	110,467	0.005235	0.000096	110,467	0.005628	0.000737	110,467	0.005341	0.000708	110,467	0.005486	0.000741
230	Tyson Foods, Inc.	TSN	1.8%	6.25%	n/a	7.00%	32,182	0.001525	0.000027	32,182	0.001640	0.000102	–	–	–	32,182	0.001598	0.000112
231	Flowserve Corporation	FLS	1.6%	16.59%	15.19%	13.50%	6,236	0.000296	0.000005	6,236	0.000318	0.000053	6,236	0.000302	0.000046	6,236	0.000310	0.000042
232	Aflac Incorporated	AFL	2.1%	4.20%	4.15%	7.50%	38,919	0.001844	0.000039	38,919	0.001983	0.000083	38,919	0.001882	0.000078	38,919	0.001933	0.000145
233	Intuit Inc.	INTU	0.8%	14.12%	16.28%	13.50%	70,025	0.003319	0.000026	70,025	0.003568	0.000504	70,025	0.003386	0.000551	70,025	0.003478	0.000469
234	Walmart Inc.	WMT	1.8%	4.56%	4.73%	7.50%	333,412	0.015801	0.000288	333,412	0.016987	0.000775	333,412	0.016122	0.000763	333,412	0.016558	0.001242
235	Edison International	EIX	3.4%	3.90%	5.24%	14.00%	23,664	0.001121	0.000038	23,664	0.001206	0.000047	23,664	0.001144	0.000060	23,664	0.001175	0.000165
236	American Airlines Group Inc.	AAL	1.4%	13.33%	5.94%	7.50%	12,601	0.000597	0.000008	12,601	0.000642	0.000086	12,601	0.000609	0.000036	12,601	0.000626	0.000047
237	Deere & Company	DE	1.9%	16.26%	7.00%	14.00%	51,778	0.002454	0.000045	51,778	0.002638	0.000429	51,778	0.002504	0.000175	51,778	0.002571	0.000360
238	Atmos Energy Corporation	ATO	2.0%	6.50%	6.67%	7.50%	13,271	0.000629	0.000013	13,271	0.000676	0.000044	13,271	0.000642	0.000043	13,271	0.000659	0.000049
239	MGM Resorts International	MGM	1.8%	NMF	9.41%	14.00%	15,295	0.000725	0.000013	–	–	–	15,295	0.000740	0.000070	15,295	0.000760	0.000106

	Company	Ticker	Dividend Yield	EPS Growth Rates IBES	EPS Growth Rates Zacks	EPS Growth Rates Value Line	Market Cap ($Millions)	Weighted Dividend Yield Weight	Weighted Dividend Yield Product	Mkt. Cap.	Weighted IBES Weight	Product	Mkt. Cap.	Weighted Zacks Weight	Product	Mkt. Cap.	Weighted Value Line Weight	Product
	(a)		(b)	(c)	(d)	(b)	(b)											
240	Franklin Resources, Inc	BEN	3.6%	NMF	7.00%	7.50%	14,902	0.000706	0.000027	–	–	–	14,902	0.000721	0.000050	14,902	0.000740	0.000056
241	Exxon Mobil Corporation	XOM	4.8%	9.69%	10.95%	14.00%	306,028	0.014503	0.000698	306,028	0.015592	0.001511	306,028	0.014798	0.001620	306,028	0.015198	0.002128
242	PACCAR Inc	PCAR	4.7%	NMF	7.00%	7.50%	24,369	0.001155	0.000054	–	–	–	24,369	0.001178	0.000082	24,369	0.001210	0.000091
243	Advance Auto Parts, Inc	AAP	0.2%	18.00%	11.56%	14.00%	10,908	0.000517	0.000001	10,908	0.000556	0.000100	10,908	0.000527	0.000061	10,908	0.000542	0.000076
244	Discover Financial Services	DFS	2.1%	10.35%	7.60%	7.50%	26,753	0.001268	0.000027	26,753	0.001363	0.000141	26,753	0.001294	0.000098	26,753	0.001329	0.000100
245	The Estee Lauder Companies Inc	EL	1.0%	11.39%	12.65%	14.00%	69,793	0.003308	0.000033	69,793	0.003556	0.000405	69,793	0.003375	0.000427	69,793	0.003466	0.000485
246	MetLife, Inc	MET	3.7%	6.64%	8.39%	7.50%	44,793	0.002123	0.000079	44,793	0.002282	0.000152	44,793	0.002166	0.000182	44,793	0.002225	0.000167
247	NIKE, Inc	NKE	1.0%	16.42%	13.00%	14.00%	137,952	0.006538	0.000065	137,952	0.007029	0.001154	137,952	0.006670	0.000867	137,952	0.006851	0.000959
248	Equifax, Inc	EFX	1.1%	3.44%	8.73%	7.50%	17,088	0.000810	0.000009	17,088	0.000871	0.000030	17,088	0.000826	0.000072	17,088	0.000849	0.000064
249	Xylem Inc	XYL	1.2%	13.42%	16.50%	14.00%	14,039	0.000665	0.000008	14,039	0.000715	0.000096	14,039	0.000679	0.000112	14,039	0.000697	0.000098
250	PPG Industries, Inc	PPG	1.7%	8.87%	9.18%	7.50%	28,518	0.001351	0.000023	28,518	0.001453	0.000129	28,518	0.001379	0.000127	28,518	0.001416	0.000106
251	MarketAxess Holdings Inc	MKTX	0.6%	14.72%	n/a	14.00%	12,940	0.000613	0.000004	12,940	0.000659	0.000097	–	–	–	12,940	0.000643	0.000090
252	TE Connectivity Ltd	TEL	2.0%	10.40%	10.71%	7.50%	31,750	0.001505	0.000029	31,750	0.001618	0.000168	31,750	0.001535	0.000164	31,750	0.001577	0.000118
253	Loews Corporation	L	0.5%	NMF	n/a	14.00%	15,448	0.000732	0.000004	–	–	–	–	–	–	15,448	0.000767	0.000107
254	D.R. Horton, Inc	DHI	1.2%	13.00%	11.00%	7.50%	18,809	0.000891	0.000011	18,809	0.000958	0.000125	18,809	0.000909	0.000100	18,809	0.000934	0.000070
255	Brown-Forman Corporation	BF.B	1.0%	7.02%	7.50%	14.50%	30,706	0.001455	0.000015	30,706	0.001564	0.000110	30,706	0.001485	0.000111	30,706	0.001525	0.000221
256	FedEx Corporation	FDX	1.8%	6.02%	12.00%	7.50%	39,776	0.001885	0.000034	39,776	0.002027	0.000122	39,776	0.001923	0.000231	39,776	0.001975	0.000148
257	Cboe Global Markets, Inc	CBOE	1.2%	2.75%	9.00%	14.50%	13,003	0.000616	0.000008	13,003	0.000662	0.000018	13,003	0.000629	0.000057	13,003	0.000646	0.000094
258	American Tower Corporation (REIT)	AMT	1.9%	NMF	16.08%	7.50%	100,453	0.004761	0.000089	–	–	–	100,453	0.004857	0.000781	100,453	0.004989	0.000374
259	Arthur J. Gallagher & Co	AJG	1.9%	10.07%	9.63%	14.50%	16,648	0.000789	0.000015	16,648	0.000848	0.000085	16,648	0.000805	0.000078	16,648	0.000827	0.000120
260	Ralph Lauren Corporation	RL	2.9%	7.35%	3.30%	8.00%	7,400	0.000351	0.000010	7,400	0.000377	0.000028	7,400	0.000358	0.000012	7,400	0.000367	0.000029
261	Union Pacific Corporation	UNP	2.3%	12.02%	10.00%	14.50%	117,803	0.005583	0.000130	117,803	0.006002	0.000721	117,803	0.005696	0.000570	117,803	0.005850	0.000848
262	Bristol-Myers Squibb Company	BMY	3.3%	4.90%	4.74%	8.00%	81,903	0.003881	0.000127	81,903	0.004173	0.000204	81,903	0.003960	0.000188	81,903	0.004067	0.000325
263	Wynn Resorts, Limited	WYNN	3.6%	13.56%	10.00%	14.50%	11,996	0.000569	0.000020	11,996	0.000611	0.000083	11,996	0.000580	0.000058	11,996	0.000596	0.000086
264	Genuine Parts Company	GPC	3.1%	4.80%	5.41%	8.00%	14,172	0.000672	0.000021	14,172	0.000722	0.000035	14,172	0.000685	0.000037	14,172	0.000704	0.000056
265	The Cooper Companies, Inc	COO	0.0%	10.00%	10.33%	14.50%	14,882	0.000705	0.000000	14,882	0.000758	0.000076	14,882	0.000720	0.000074	14,882	0.000739	0.000107
266	FirstEnergy Corporation	FE	3.3%	NMF	6.00%	8.00%	25,599	0.001213	0.000040	–	–	–	25,599	0.001238	0.000074	25,599	0.001271	0.000102
267	Jacobs Engineering Group Inc	JEC	0.7%	15.64%	11.00%	14.50%	12,531	0.000594	0.000004	12,531	0.000638	0.000100	12,531	0.000606	0.000067	12,531	0.000622	0.000090
268	Cummins Inc	CMI	3.2%	2.30%	6.27%	8.00%	25,567	0.001212	0.000039	25,567	0.001303	0.000030	25,567	0.001236	0.000078	25,567	0.001270	0.000102
269	Microsoft Corporation	MSFT	1.3%	14.52%	11.01%	14.50%	1,081,443	0.051250	0.000666	1,081,443	0.055100	0.008001	1,081,443	0.052292	0.005757	1,081,443	0.053707	0.007787
270	Cisco Systems, Inc	CSCO	2.9%	6.63%	6.80%	8.00%	212,157	0.010054	0.000287	212,157	0.010809	0.000738	212,157	0.010259	0.000698	212,157	0.010536	0.000843
271	Cigna Corporation	CI	0.0%	12.65%	11.71%	14.50%	62,196	0.002948	0.000001	62,196	0.003169	0.000401	62,196	0.003007	0.000352	62,196	0.003089	0.000448
272	The PNC Financial Services Group, Inc	PNC	3.3%	5.03%	6.81%	8.00%	63,027	0.002987	0.000097	63,027	0.003211	0.000162	63,027	0.003048	0.000208	63,027	0.003130	0.000250
273	CSX Corporation	CSX	1.4%	9.44%	12.97%	14.50%	56,503	0.002678	0.000036	56,503	0.002879	0.000272	56,503	0.002732	0.000354	56,503	0.002806	0.000407
274	Target Corporation	TGT	2.5%	9.19%	7.07%	8.00%	55,158	0.002614	0.000064	55,158	0.002810	0.000258	55,158	0.002667	0.000189	55,158	0.002739	0.000219
275	Automatic Data Processing, Inc	ADP	2.2%	16.55%	13.00%	14.50%	69,397	0.003289	0.000071	69,397	0.003536	0.000585	69,397	0.003356	0.000436	69,397	0.003446	0.000500
276	Nasdaq, Inc	NDAQ	1.9%	5.77%	7.09%	8.00%	16,817	0.000797	0.000015	16,817	0.000857	0.000049	16,817	0.000813	0.000058	16,817	0.000835	0.000067
277	Vulcan Materials Company	VMC	0.8%	18.80%	17.54%	14.50%	19,874	0.000942	0.000008	19,874	0.001013	0.000190	19,874	0.000961	0.000169	19,874	0.000987	0.000143
278	PulteGroup, Inc	PHM	1.3%	3.80%	7.41%	8.00%	9,751	0.000462	0.000006	9,751	0.000497	0.000019	9,751	0.000471	0.000035	9,751	0.000484	0.000039
279	Corning Incorporated	GLW	2.9%	10.37%	9.04%	15.00%	21,500	0.001019	0.000030	21,500	0.001095	0.000114	21,500	0.001040	0.000094	21,500	0.001068	0.000160
280	AmerisourceBergen Corporation	ABC	2.0%	8.08%	7.91%	8.00%	17,635	0.000836	0.000016	17,635	0.000899	0.000073	17,635	0.000853	0.000067	17,635	0.000876	0.000070
281	Cintas Corporation	CTAS	0.9%	11.53%	10.19%	15.00%	25,968	0.001231	0.000011	25,968	0.001323	0.000153	25,968	0.001256	0.000128	25,968	0.001290	0.000193
282	McCormick & Company, Incorporated	MKC	1.5%	9.30%	8.00%	8.00%	21,208	0.001005	0.000015	21,208	0.001081	0.000100	21,208	0.001025	0.000082	21,208	0.001053	0.000084
283	FMC Corporation	FMC	1.9%	8.00%	10.32%	15.00%	11,790	0.000559	0.000011	11,790	0.000601	0.000048	11,790	0.000570	0.000059	11,790	0.000586	0.000088
284	Constellation Brands Inc	STZ	1.5%	6.51%	8.07%	8.00%	39,721	0.001882	0.000028	39,721	0.002024	0.000132	39,721	0.001921	0.000155	39,721	0.001973	0.000158
285	Norfolk Southern Corporation	NSC	2.1%	11.78%	11.31%	15.00%	48,098	0.002279	0.000047	48,098	0.002451	0.000289	48,098	0.002326	0.000263	48,098	0.002389	0.000358
286	Lennar Corporation	LEN	0.3%	9.45%	8.58%	8.00%	17,328	0.000821	0.000002	17,328	0.000883	0.000083	17,328	0.000838	0.000072	17,328	0.000861	0.000069
287	Teleflex Incorporated	TFX	0.4%	13.20%	14.00%	15.00%	15,798	0.000749	0.000003	15,798	0.000805	0.000106	15,798	0.000764	0.000107	15,798	0.000785	0.000118
288	Eastman Chemical Company	EMN	3.4%	4.51%	8.75%	8.00%	9,911	0.000470	0.000016	9,911	0.000505	0.000023	9,911	0.000479	0.000042	9,911	0.000492	0.000039
289	The Progressive Corporation	PGR	0.5%	5.01%	7.33%	15.50%	44,263	0.002098	0.000011	44,263	0.002255	0.000113	44,263	0.002140	0.000157	44,263	0.002198	0.000341
290	United Parcel Service, Inc	UPS	3.4%	7.47%	8.76%	8.00%	102,276	0.004847	0.000164	102,276	0.005211	0.000389	102,276	0.004945	0.000433	102,276	0.005079	0.000406
291	The Boeing Company	BA	2.3%	9.61%	8.25%	15.50%	216,326	0.010252	0.000239	216,326	0.011022	0.001059	216,326	0.010460	0.000863	216,326	0.010743	0.001665
292	BB&T Corporation	BBT	3.4%	10.01%	8.99%	8.00%	40,438	0.001916	0.000065	40,438	0.002060	0.000206	40,438	0.001955	0.000176	40,438	0.002008	0.000161
293	AMETEK, Inc	AME	0.6%	6.80%	9.56%	15.50%	20,599	0.000976	0.000006	20,599	0.001050	0.000071	20,599	0.000996	0.000095	20,599	0.001023	0.000159
294	Hasbro, Inc	HAS	2.3%	13.90%	10.87%	8.00%	15,261	0.000723	0.000016	15,261	0.000778	0.000108	15,261	0.000738	0.000079	15,261	0.000758	0.000061
295	ResMed Inc	RMD	1.2%	14.20%	10.60%	15.50%	19,138	0.000907	0.000011	19,138	0.000975	0.000138	19,138	0.000925	0.000098	19,138	0.000950	0.000147
296	Martin Marietta Materials, Inc	MLM	0.8%	16.20%	11.42%	8.00%	16,777	0.000795	0.000007	16,777	0.000855	0.000138	16,777	0.000811	0.000093	16,777	0.000833	0.000067
297	Quanta Services, Inc	PWR	0.4%	12.47%	n/a	15.50%	5,385	0.000255	0.000001	5,385	0.000274	0.000034	–	–	–	5,385	0.000267	0.000041
298	HP Inc	HPQ	3.6%	5.02%	3.21%	8.50%	27,786	0.001317	0.000048	27,786	0.001416	0.000071	27,786	0.001344	0.000043	27,786	0.001380	0.000117
299	Regency Centers Corporation	REG	3.4%	9.10%	3.53%	16.00%	11,418	0.000541	0.000019	11,418	0.000582	0.000053	11,418	0.000552	0.000019	11,418	0.000567	0.000091
300	Iron Mountain Incorporated	IRM	7.6%	3.60%	3.81%	8.50%	9,229	0.000437	0.000033	9,229	0.000470	0.000017	9,229	0.000446	0.000017	9,229	0.000458	0.000039
301	Mastercard Incorporated	MA	0.5%	16.96%	15.86%	16.00%	280,325	0.013285	0.000064	280,325	0.014283	0.002422	280,325	0.013555	0.002150	280,325	0.013922	0.002227
302	Applied Materials, Inc	AMAT	1.7%	8.52%	5.00%	8.50%	47,752	0.002263	0.000037	47,752	0.002433	0.000207	47,752	0.002309	0.000115	47,752	0.002371	0.000202
303	Cimarex Energy Co	XEC	1.6%	14.28%	n/a	16.00%	5,157	0.000244	0.000004	5,157	0.000263	0.000038	–	–	–	5,157	0.000256	0.000041
304	McKesson Corporation	MCK	1.1%	7.26%	6.90%	8.50%	26,955	0.001277	0.000014	26,955	0.001373	0.000100	26,955	0.001303	0.000090	26,955	0.001339	0.000114
305	Chevron Corporation	CVX	3.9%	4.87%	6.00%	16.50%	234,758	0.011125	0.000431	234,758	0.011961	0.000583	234,758	0.011351	0.000681	234,758	0.011659	0.001924
306	JPMorgan Chase & Co	JPM	3.0%	5.72%	7.00%	8.50%	381,716	0.018090	0.000546	381,716	0.019449	0.001112	381,716	0.018457	0.001292	381,716	0.018957	0.001611
307	L3Harris Technologies Inc	LHX	1.4%	17.74%	8.00%	16.50%	25,377	0.001203	0.000017	25,377	0.001293	0.000229	25,377	0.001227	0.000098	25,377	0.001260	0.000208
308	Medtronic PLC	MDT	2.0%	7.53%	7.32%	8.50%	148,842	0.007054	0.000138	148,842	0.007584	0.000571	148,842	0.007197	0.000527	148,842	0.007392	0.000628
309	Hilton Worldwide Holdings Inc	HLT	0.6%	15.58%	8.51%	17.00%	27,555	0.001306	0.000008	27,555	0.001404	0.000219	27,555	0.001332	0.000113	27,555	0.001368	0.000233
310	Quest Diagnostics Incorporated	DGX	2.0%	5.58%	7.38%	8.50%	14,272	0.000676	0.000014	14,272	0.000727	0.000041	14,272	0.000690	0.000051	14,272	0.000709	0.000060
311	ONEOK, Inc	OKE	5.0%	15.20%	11.51%	17.00%	31,010	0.001470	0.000073	31,010	0.001580	0.000240	31,010	0.001499	0.000173	31,010	0.001540	0.000262
312	Altria Group, Inc	MO	8.4%	6.59%	7.65%	8.50%	74,948	0.003552	0.000298	74,948	0.003819	0.000252	74,948	0.003624	0.000277	74,948	0.003722	0.000316
313	Diamondback Energy, Inc	FANG	0.8%	NMF	NMF	17.00%	15,957	0.000756	0.000006	–	–	–	–	–	–	15,957	0.000792	0.000135
314	Mondelez International, Inc	MDLZ	2.1%	5.80%	7.70%	8.50%	79,863	0.003785	0.000078	79,863	0.004069	0.000236	79,863	0.003862	0.000297	79,863	0.003966	0.000337
315	Weyerhaeuser Company	WY	4.9%	5.00%	5.00%	17.50%	20,701	0.000981	0.000048	20,701	0.001055	0.000053	20,701	0.001001	0.000050	20,701	0.001028	0.000180
316	Best Buy Co., Inc	BBY	3.1%	7.15%	7.90%	8.50%	17,911	0.000849	0.000026	17,911	0.000913	0.000065	17,911	0.000866	0.000068	17,911	0.000890	0.000076
317	Willis Towers Watson Public Limited Company	WLTW	1.3%	9.97%	10.56%	17.50%	25,564	0.001212	0.000016	25,564	0.001303	0.000130	25,564	0.001236	0.000131	25,564	0.001270	0.000222
318	Harley-Davidson, Inc	HOG	4.3%	8.50%	8.00%	8.50%	5,453	0.000258	0.000011	5,453	0.000278	0.000024	5,453	0.000264	0.000021	5,453	0.000271	0.000023
319	E*TRADE Financial Corporation	ETFC	1.2%	6.01%	10.91%	17.50%	10,817	0.000513	0.000006	10,817	0.000551	0.000033	10,817	0.000523	0.000057	10,817	0.000537	0.000094
320	McDonald's Corporation	MCD	2.3%	6.74%	8.41%	8.50%	159,869	0.007576	0.000173	159,869	0.008145	0.000549	159,869	0.007730	0.000650	159,869	0.007939	0.000675
321	Global Payments Inc	GPN	0.0%	16.33%	16.82%	17.50%	25,488	0.001208	0.000000	25,488	0.001299	0.000212	25,488	0.001232	0.000207	25,488	0.001266	0.000222
322	Northern Trust Corporation	NTRS	2.9%	NMF	8.52%	8.50%	20,582	0.000975	0.000028	–	–	–	20,582	0.000995	0.000085	20,582	0.001022	0.000087
323	Fidelity National Information Services, Inc	FIS	1.1%	2.32%	8.94%	18.00%	43,384	0.002056	0.000022	43,384	0.002210	0.000051	43,384	0.002098	0.000188	43,384	0.002155	0.000388
324	Costco Wholesale Corporation	COST	0.9%	9.09%	8.87%	8.50%	126,591	0.005999	0.000054	126,591	0.006450	0.000586	126,591	0.006121	0.000543	126,591	0.006287	0.000534
325	HollyFrontier Corporation	HFC	2.6%	NMF	10.24%	18.00%	8,756	0.000415	0.000011	–	–	–	8,756	0.000423	0.000043	8,756	0.000435	0.000078
326	Unum Group	UNM	3.9%	6.02%	9.00%	8.50%	6,195	0.000294	0.000011	6,195	0.000316	0.000019	6,195	0.000300	0.000027	6,195	0.000308	0.000026
327	Visa Inc	V	0.6%	15.87%	15.61%	18.00%	349,457	0.016561	0.000106	349,457	0.017805	0.002826	349,457	0.016898	0.002638	349,457	0.017355	0.003124
328	Honeywell International Inc	HON	2.0%	6.75%	9.28%	8.50%	119,992	0.005687	0.000112	119,992	0.006114	0.000413	119,992	0.005802	0.000538	119,992	0.005959	0.000507
329	MSCI Inc	MSCI	1.2%	14.30%	10.00%	18.50%	19,936	0.000945	0.000011	19,936	0.001016	0.000145	19,936	0.000964	0.000096	19,936	0.000990	0.000183
330	Celanese Corporation	CE	2.0%	5.40%	10.00%	8.50%	15,319	0.000726	0.000015	15,319	0.000781	0.000042	15,319	0.000741	0.000074	15,319	0.000761	0.000065
331	Everest Re Group, Ltd	RE	2.3%	NMF	10.00%	18.50%	10,686	0.000506	0.000011	–	–	–	10,686	0.000517	0.000052	10,686	0.000531	0.000098
332	Merck & Co., Inc	MRK	2.6%	9.62%	10.02%	8.50%	215,534	0.010214	0.000268	215,534	0.010982	0.001056	215,534	0.010422	0.001044	215,534	0.010704	0.000910
333	JEFFERIES FINANCIAL GROUP INC	JEF	2.5%	18.00%	n/a	18.50%	5,715	0.000271	0.000007	5,715	0.000291	0.000052	–	–	–	5,715	0.000284	0.000053
334	Allegion PLC	ALLE	1.1%	7.89%	11.09%	8.50%	9,544	0.000452	0.000005	9,544	0.000486	0.000038	9,544	0.000461	0.000051	9,544	0.000474	0.000040
335	Schlumberger Limited	SLB	5.3%	15.04%	9.45%	19.50%	52,222	0.002475	0.000131	52,222	0.002661	0.000400	52,222	0.002525	0.000239	52,222	0.002593	0.000506
336	W.W. Grainger, Inc	GWW	2.0%	9.70%	11.10%	8.50%	15,943	0.000756	0.000015	15,943	0.000812	0.000079	15,943	0.000771	0.000086	15,943	0.000792	0.000067
337	Anthem, Inc	ANTM	1.3%	17.78%	13.97%	19.50%	65,364	0.003098	0.000039	65,364	0.003330	0.000592	65,364	0.003161	0.000442	65,364	0.003246	0.000633
338	Lam Research Corporation	LRCX	1.9%	NMF	12.00%	8.50%	34,210	0.001621	0.000031	–	–	–	34,210	0.001654	0.000199	34,210	0.001699	0.000144
339	Concho Resources Inc	CXO	0.7%	12.03%	n/a	19.50%	14,579	0.000691	0.000005	14,579	0.000743	0.000089	–	–	–	14,579	0.000724	0.000141
340	The Goldman Sachs Group, Inc	GS	2.3%	2.81%	12.00%	8.50%	77,599	0.003677	0.000085	77,599	0.003954	0.000111	77,599	0.003752	0.000450	77,599	0.003854	0.000328
341	Williams Companies, Inc. (The)	WMB	6.1%	8.78%	6.50%	20.00%	30,045	0.001424	0.000087	30,045	0.001531	0.000134	30,045	0.001453	0.000094	30,045	0.001492	0.000298
342	Fastenal Company	FAST	2.7%	19.00%	16.00%	8.50%	18,578	0.000880	0.000024	18,578	0.000947	0.000180	18,578	0.000898	0.000144	18,578	0.000923	0.000078
343	The Mosaic Company	MOS	1.1%	4.12%	7.00%	NMF	8,099	0.000384	0.000004	8,099	0.000413	0.000017	8,099	0.000392	0.000027	–	–	–
344	International Flavors & Fragrances Inc	IFF	2.5%	3.80%	n/a	8.50%	13,118	0.000622	0.000015	13,118	0.000668	0.000025	–	–	–	13,118	0.000651	0.000055
345	Equinix, Inc	EQIX	1.8%	NMF	14.57%	NMF	48,265	0.002287	0.000041	–	–	–	48,265	0.002334	0.000340	–	–	–
346	Cincinnati Financial Corporation	CINF	2.0%	5.72%	n/a	8.50%	18,665	0.000885	0.000017	18,665	0.000951	0.000054	–	–	–	18,665	0.000927	0.000079
347	Sealed Air Corporation	SEE	1.6%	9.50%	10.16%	NMF	6,384	0.000303	0.000005	6,384	0.000325	0.000031	6,384	0.000309	0.000031	–	–	–
348	People's United Financial, Inc	PBCT	4.5%	13.73%	2.00%	9.00%	6,356	0.000301	0.000013	6,356	0.000324	0.000044	6,356	0.000307	0.000006	6,356	0.000316	0.000028
349	Freeport-McMoRan Inc	FCX	1.9%	0.03%	n/a	NMF	15,163	0.000719	0.000014	15,163	0.000773	0.000000	–	–	–	–	–	–
350	Exelon Corporation	EXC	3.2%	NMF	3.42%	9.00%	46,366	0.002197	0.000069	–	–	–	46,366	0.002242	0.000077	46,366	0.002303	0.000207
351	Expedia Group, Inc	EXPE	1.0%	13.18%	13.68%	NMF	20,107	0.000953	0.000010	20,107	0.001024	0.000135	20,107	0.000972	0.000133	–	–	–
352	Procter & Gamble Company (The)	PG	2.5%	7.30%	7.11%	9.00%	305,329	0.014470	0.000355	305,329	0.015557	0.001136	305,329	0.014764	0.001050	305,329	0.015163	0.001365
353	Halliburton Company	HAL	3.4%	1.35%	6.36%	NMF	18,284	0.000866	0.000030	18,284	0.000932	0.000013	18,284	0.000884	0.000056	–	–	–
354	Illinois Tool Works Inc	ITW	2.8%	4.07%	7.34%	9.00%	50,424	0.002390	0.000066	50,424	0.002569	0.000105	50,424	0.002438	0.000179	50,424	0.002504	0.000225
355	Ball Corporation	BLL	0.8%	15.26%	5.50%	NMF	24,649	0.001168	0.000009	24,649	0.001256	0.000192	24,649	0.001192	0.000066	–	–	–
356	Hormel Foods Corporation	HRL	2.1%	5.00%	7.50%	9.00%	22,927	0.001087	0.000022	22,927	0.001168	0.000058	22,927	0.001109	0.000083	22,927	0.001139	0.000102
357	Devon Energy Corporation	DVN	1.4%	NMF	10.55%	NMF	10,625	0.000504	0.000007	–	–	–	10,625	0.000514	0.000054	–	–	–
358	Leidos Holdings, Inc	LDOS	1.6%	10.41%	7.50%	9.00%	12,581	0.000596	0.000009	12,581	0.000641	0.000067	12,581	0.000608	0.000046	12,581	0.000625	0.000056
359	SBA Communications Corporation	SBAC	0.6%	NMF	10.00%	NMF	28,409	0.001346	0.000008	–	–	–	28,409	0.001374	0.000137	–	–	–

	Company	Ticker	Dividend Yield	EPS Growth Rates IBES	Zacks	Value Line	Market Cap ($Millions)	Weighted Dividend Yield Weight	Product	Mkt. Cap.	Weighted IBES Weight	Product	Mkt. Cap.	Weighted Zacks Weight	Product	Mkt. Cap.	Weighted Value Line Weight	Product
	(a)		(b)	(c)	(d)	(b)	(b)											
360	Robert Half International Inc.	RHI	2.3%	6.60%	7.82%	9.00%	6,422	0.000304	0.000007	6,422	0.000327	0.000022	6,422	0.000311	0.000024	6,422	0.000319	0.000029
361	Occidental Petroleum Corporation	OXY	6.9%	NMF	5.00%	NMF	34,265	0.001624	0.000112	--	--	--	34,265	0.001657	0.000083	--	--	--
362	Waste Management, Inc.	WM	1.8%	8.55%	8.56%	9.00%	48,623	0.002304	0.000041	48,623	0.002477	0.000212	48,623	0.002351	0.000201	48,623	0.002415	0.000217
363	EOG Resources, Inc.	EOG	1.4%	12.44%	8.70%	NMF	47,385	0.002246	0.000032	47,385	0.002414	0.000300	47,385	0.002291	0.000199	--	--	--
364	Stanley Black & Decker, Inc.	SWK	1.9%	7.67%	8.69%	9.00%	21,705	0.001029	0.000020	21,705	0.001106	0.000085	21,705	0.001050	0.000091	21,705	0.001078	0.000097
365	Broadcom Inc.	AVGO	3.7%	20.00%	11.75%	NMF	115,675	0.005482	0.000200	115,675	0.005894	0.001179	115,675	0.005593	0.000657	--	--	--
366	Church & Dwight Co., Inc.	CHD	1.3%	8.17%	8.70%	9.00%	17,971	0.000852	0.000011	17,971	0.000916	0.000075	17,971	0.000869	0.000076	17,971	0.000892	0.000080
367	Kinder Morgan, Inc.	KMI	4.8%	6.50%	5.00%	NMF	46,811	0.002218	0.000107	46,811	0.002385	0.000155	46,811	0.002263	0.000113	--	--	--
368	Eaton Corporation, PLC	ETN	3.4%	8.09%	8.75%	9.00%	35,494	0.001682	0.000057	35,494	0.001808	0.000146	35,494	0.001716	0.000150	35,494	0.001763	0.000159
369	ConocoPhillips	COP	2.0%	4.31%	9.50%	NMF	66,575	0.003155	0.000064	66,575	0.003392	0.000146	66,575	0.003219	0.000306	--	--	--
370	United Technologies Corporation	UTX	2.1%	8.65%	8.80%	9.00%	118,665	0.005624	0.000120	118,665	0.006046	0.000523	118,665	0.005738	0.000505	118,665	0.005893	0.000530
371	Pioneer Natural Resources Company	PXD	1.1%	NMF	NMF	NMF	22,717	0.001077	0.000012	--	--	--	--	--	--	--	--	--
372	C.H. Robinson Worldwide, Inc.	CHRW	2.3%	5.66%	9.00%	9.00%	11,619	0.000551	0.000013	11,619	0.000592	0.000035	11,619	0.000562	0.000051	11,619	0.000577	0.000052
373	Nielsen Holdings Plc	NLSN	6.2%	NMF	12.00%	NMF	8,049	0.000381	0.000024	--	--	--	8,049	0.000389	0.000047	--	--	--
374	Lincoln National Corporation	LNC	2.6%	11.38%	9.00%	9.00%	12,225	0.000579	0.000015	12,225	0.000623	0.000071	12,225	0.000591	0.000053	12,225	0.000607	0.000055
375	Cabot Oil & Gas Corporation	COG	2.0%	NMF	15.00%	NMF	7,602	0.000360	0.000007	--	--	--	7,602	0.000368	0.000055	--	--	--
376	The Travelers Companies, Inc.	TRV	2.2%	10.63%	9.25%	9.00%	38,248	0.001813	0.000040	38,248	0.001949	0.000207	38,248	0.001849	0.000171	38,248	0.001900	0.000171
377	Apache Corporation	APA	3.9%	12.45%	8.00%	NMF	9,685	0.000459	0.000018	9,685	0.000493	0.000061	9,685	0.000468	0.000026	--	--	--
378	BlackRock, Inc.	BLK	3.0%	6.47%	9.83%	9.00%	68,614	0.003252	0.000097	68,614	0.003496	0.000226	68,614	0.003318	0.000326	68,614	0.003408	0.000307
379	Dow Inc.	DOW	6.0%	3.22%	3.66%	n/a	35,407	0.001678	0.000100	35,407	0.001804	0.000058	35,407	0.001712	0.000063	--	--	--
380	The Home Depot, Inc.	HD	2.7%	8.54%	9.95%	9.00%	250,020	0.011849	0.000320	250,020	0.012739	0.001088	250,020	0.012089	0.001203	250,020	0.012417	0.001117
381	Alexandria Real Estate Equities, Inc.	ARE	2.6%	0.10%	4.77%	n/a	17,100	0.000810	0.000021	17,100	0.000871	0.000001	17,100	0.000827	0.000039	--	--	--
382	Accenture PLC	ACN	1.6%	8.83%	10.33%	9.00%	124,167	0.005884	0.000097	124,167	0.006326	0.000559	124,167	0.006004	0.000620	124,167	0.006166	0.000555
383	CF Industries Holdings, Inc.	CF	2.5%	NMF	6.00%	n/a	10,948	0.000519	0.000013	--	--	--	10,948	0.000529	0.000032	--	--	--
384	Synchrony Financial	SYF	2.6%	11.00%	10.33%	9.00%	22,770	0.001079	0.000028	22,770	0.001160	0.000128	22,770	0.001101	0.000114	22,770	0.001131	0.000102
385	Evergy Inc.	EVRG	3.1%	6.80%	6.59%	n/a	15,435	0.000731	0.000023	15,435	0.000786	0.000053	15,435	0.000746	0.000049	--	--	--
386	Marsh & McLennan Companies, Inc.	MMC	1.6%	8.75%	12.14%	9.00%	51,792	0.002454	0.000044	51,792	0.002639	0.000231	51,792	0.002504	0.000304	51,792	0.002572	0.000231
387	Lamb Weston Holdings Inc.	LW	1.1%	7.20%	7.50%	n/a	10,778	0.000511	0.000006	10,778	0.000549	0.000040	10,778	0.000521	0.000039	--	--	--
388	Cerner Corporation	CERN	1.1%	14.15%	13.19%	9.00%	21,528	0.001020	0.000011	21,528	0.001097	0.000155	21,528	0.001041	0.000137	21,528	0.001069	0.000096
389	Marathon Oil Corporation	MRO	1.5%	NMF	7.76%	n/a	10,484	0.000497	0.000008	--	--	--	10,484	0.000507	0.000039	--	--	--
390	Expeditors International of Washington, Inc.	EXPD	1.3%	4.86%	n/a	9.00%	12,683	0.000601	0.000008	12,683	0.000646	0.000031	--	--	--	12,683	0.000630	0.000057
391	Baker Hughes, a GE company	BHGE	3.1%	NMF	8.00%	n/a	11,976	0.000568	0.000018	--	--	--	11,976	0.000579	0.000046	--	--	--
392	Leggett & Platt, Incorporated	LEG	3.9%	5.20%	n/a	9.00%	5,427	0.000257	0.000010	5,427	0.000277	0.000014	--	--	--	5,427	0.000270	0.000024
393	The AES Corporation	AES	3.5%	9.00%	6.49%	n/a	10,588	0.000502	0.000017	10,588	0.000539	0.000049	10,588	0.000512	0.000043	--	--	--
394	M&T Bank Corporation	MTB	2.6%	6.18%	5.15%	9.50%	21,061	0.000998	0.000025	21,061	0.001073	0.000066	21,061	0.001018	0.000052	21,061	0.001046	0.000099
395	American International Group, Inc.	AIG	2.2%	NMF	10.00%	n/a	50,359	0.002387	0.000053	--	--	--	50,359	0.002435	0.000244	--	--	--
396	Citizens Financial Group, Inc.	CFG	4.0%	6.04%	5.42%	9.50%	16,562	0.000785	0.000031	16,562	0.000844	0.000051	16,562	0.000801	0.000043	16,562	0.000823	0.000078
397	National Oilwell Varco, Inc.	NOV	0.9%	NMF	15.00%	n/a	8,833	0.000419	0.000004	--	--	--	8,833	0.000427	0.000064	--	--	--
398	Walgreens Boots Alliance, Inc.	WBA	3.4%	1.66%	6.68%	9.50%	49,285	0.002336	0.000078	49,285	0.002511	0.000042	49,285	0.002383	0.000159	49,285	0.002448	0.000233
399	Helmerich & Payne, Inc.	HP	6.6%	NMF	NMF	n/a	4,707	0.000223	0.000015	--	--	--	--	--	--	--	--	--
400	IDEX Corporation	IEX	1.2%	13.00%	7.50%	9.50%	12,641	0.000599	0.000007	12,641	0.000644	0.000084	12,641	0.000611	0.000046	12,641	0.000628	0.000060
401	NRG Energy, Inc.	NRG	0.3%	NMF	NMF	n/a	10,033	0.000475	0.000001	--	--	--	--	--	--	--	--	--
402	Zions Bancorporation	ZION	3.1%	1.00%	7.51%	9.50%	7,888	0.000374	0.000011	7,888	0.000402	0.000004	7,888	0.000381	0.000029	7,888	0.000392	0.000037
403	Noble Energy Inc.	NBL	2.1%	15.49%	n/a	n/a	11,254	0.000533	0.000011	11,254	0.000573	0.000089	--	--	--	--	--	--
404	Globe Life Inc.	GL	0.7%	7.85%	7.60%	9.50%	10,302	0.000488	0.000004	10,302	0.000525	0.000041	10,302	0.000498	0.000038	10,302	0.000512	0.000049
405	News Corporation	NWSA	1.4%	18.33%	n/a	n/a	8,162	0.000387	0.000006	8,162	0.000416	0.000076	--	--	--	--	--	--
406	Rockwell Automation, Inc.	ROK	2.4%	5.29%	7.84%	9.50%	19,072	0.000904	0.000022	19,072	0.000972	0.000051	19,072	0.000922	0.000072	19,072	0.000947	0.000090
407	Arconic Inc.	ARNC	0.3%	NMF	n/a	n/a	11,947	0.000566	0.000002	--	--	--	--	--	--	--	--	--
408	American Water Works Company, Inc.	AWK	1.7%	8.20%	8.08%	9.50%	22,108	0.001048	0.000018	22,108	0.001126	0.000092	22,108	0.001069	0.000086	22,108	0.001098	0.000104
409	Hess Corporation	HES	1.5%	NMF	n/a	n/a	19,968	0.000946	0.000014	--	--	--	--	--	--	--	--	--
410	Masco Corporation	MAS	1.3%	7.90%	8.21%	9.50%	11,798	0.000559	0.000007	11,798	0.000601	0.000047	11,798	0.000570	0.000047	11,798	0.000586	0.000056
411	A. O. Smith Corporation	AOS	1.8%	6.40%	6.73%	9.50%	7,972	0.000378	0.000007	7,972	0.000406	0.000026	7,972	0.000385	0.000034	7,972	0.000396	0.000038
412	Amphenol Corporation	APH	1.1%	4.70%	9.57%	9.50%	28,032	0.001328	0.000014	28,032	0.001428	0.000067	28,032	0.001355	0.000130	28,032	0.001392	0.000132
413	Ross Stores, Inc.	ROST	1.0%	8.95%	10.50%	9.50%	39,335	0.001864	0.000018	39,335	0.002004	0.000179	39,335	0.001902	0.000200	39,335	0.001953	0.000186
414	PVH Corp.	PVH	0.2%	6.23%	10.76%	9.50%	6,458	0.000306	0.000001	6,458	0.000329	0.000020	6,458	0.000312	0.000034	6,458	0.000321	0.000030
415	CBS Corporation	CBS	1.8%	12.83%	11.62%	9.50%	15,896	0.000753	0.000014	15,896	0.000810	0.000104	15,896	0.000769	0.000069	15,896	0.000789	0.000075
							21,101,253	1.000000		19,626,927	1.000000		20,680,946	1.000000		20,138,024	1.000000	
	Weighted Average								2.41%			8.88%			8.91%			10.12%
	Average														9.31%			

n/a -- Not Available
NMF - Eliminated because growth rate negative or greater than 20%.

(a) Dividend paying components of S&P 500 index from zacks.com (retrieved Sep. 26, 2019).
(b) www.valueline.com (retrieved Sep. 26, 2019)
(c) http://finance.yahoo.com (retrieved Sep. 26-27, 2019).
(d) www.zacks.com (retrieved Sep. 26, 2019)

FRED Graph Observations
Federal Reserve Economic Data
Link: https://fred.stlouisfed.org
Help: https://fred.stlouisfed.org/help-faq
Economic Research Division
Federal Reserve Bank of St. Louis

DGS30 30-Year Treasury Constant Maturity Rate, Percent,

Frequency: Daily

observation_date	DGS30	
2019-07-26	2.59	
2019-07-29	2.59	
2019-07-30	2.58	
2019-07-31	2.53	
2019-08-01	2.44	
2019-08-02	2.39	
2019-08-05	2.30	
2019-08-06	2.25	
2019-08-07	2.22	
2019-08-08	2.25	
2019-08-09	2.26	
2019-08-12	2.14	
2019-08-13	2.15	
2019-08-14	2.03	
2019-08-15	1.98	
2019-08-16	2.01	
2019-08-19	2.08	
2019-08-20	2.04	
2019-08-21	2.07	
2019-08-22	2.11	
2019-08-23	2.02	
2019-08-26	2.04	
2019-08-27	1.97	
2019-08-28	1.94	
2019-08-29	1.97	
2019-08-30	1.96	
2019-09-02	#N/A	
2019-09-03	1.95	
2019-09-04	1.97	
2019-09-05	2.06	
2019-09-06	2.02	
2019-09-09	2.11	
2019-09-10	2.19	
2019-09-11	2.22	
2019-09-12	2.22	
2019-09-13	2.37	
2019-09-16	2.31	
2019-09-17	2.27	
2019-09-18	2.25	
2019-09-19	2.22	
2019-09-20	2.17	
2019-09-23	2.16	
2019-09-24	2.09	
2019-09-25	2.18	
2019-09-26	2.15	
2019-09-27	2.13	
2019-09-30	2.12	2.16
2019-10-01	2.11	
2019-10-02	2.09	
2019-10-03	2.04	
2019-10-04	2.01	
2019-10-07	2.05	
2019-10-08	2.04	
2019-10-09	2.08	
2019-10-10	2.16	

S&P Global
Market Intelligence

Source: S&P Global Market Intelligence

Table 1: ROEs authorized January 1990-June 2019

		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	40	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
	1st quarter	10.37	9.83	9	9.47	9.05	3
	2nd quarter	9.73	9.60	7	9.43	9.50	3
	3rd quarter	9.40	9.40	2	9.75	9.75	1
	4th quarter	9.62	9.55	12	9.68	9.75	9
2015	**Full year**	**9.85**	**9.65**	**30**	**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
2019	**1st half**	**9.66**	**9.63**	**24**	**9.63**	**9.70**	**7**

Data compiled July 19, 2019.

Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Moody's Corporate, Industrial, and Utility Bond Yields

September 2019

Utility-Avg	3.44
Utility-Aa	3.24
Utility-A	3.37
Utility-Baa	3.71
Industrial-Avg	3.38
Industrial-Aaa	3.03
Industrial-Aaa	3.35
Industrial-A	3.35
Industrial-Baa	4.11
Corporate-Avg	3.42
Corporate-Aaa	3.03
Corporate-Aaa	3.14
Corporate-A	3.37
Corporate-Baa	3.91

Mnemonic:	IRCORD.IUSA	IRAAACD.IUSA	IRAACD.IUSA	IRACD.IUSA	IRBAACD.IUSA	IRINDD.IUSA	IRAAAID.IUSA
Description:	Moody's Daily Corporate Bond Yield Averages: Average Corporate - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: Aaa Corporate - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: Aa Corporate - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: A Corporate - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: Baa Corporate - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: Average Industrial - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: Aaa Industrial - Based on bonds with maturities 20 years and above, (% p.a., NSA)
Source:	Moody's Analytics	Moody's Analytics	Moody's Analytics	Moody's Analytics	Moody's Analytics	Moody's Analytics	Moody's Analytics
Native Frequency:	BUSINESS	BUSINESS	BUSINESS	BUSINESS	BUSINESS	BUSINESS	BUSINESS
Geography:	United States	United States	United States	United States	United States	United States	United States
09/02/2019	na	na	na	na	na	na	na
09/03/2019	3.24	2.86	2.95	3.19	3.75	3.22	2.86
09/04/2019	3.24	2.86	2.95	3.20	3.76	3.22	2.86
09/05/2019	3.33	2.94	3.05	3.27	3.85	3.30	2.94
09/06/2019	3.30	2.91	3.02	3.24	3.81	3.27	2.91
09/09/2019	3.37	2.99	3.09	3.31	3.86	3.34	2.99
09/10/2019	3.45	3.07	3.18	3.40	3.94	3.42	3.07
09/11/2019	3.47	3.09	3.20	3.42	3.97	3.44	3.09
09/12/2019	3.51	3.14	3.24	3.46	4.01	3.48	3.14
09/13/2019	3.62	3.25	3.34	3.56	4.11	3.58	3.25
09/16/2019	3.55	3.18	3.28	3.50	4.04	3.52	3.18
09/17/2019	3.53	3.14	3.25	3.46	4.02	3.49	3.14
09/18/2019	3.49	3.10	3.21	3.44	3.98	3.45	3.10
09/19/2019	3.46	3.07	3.19	3.41	3.96	3.42	3.07
09/20/2019	3.43	3.03	3.15	3.39	3.93	3.39	3.03
09/23/2019	3.40	3.02	3.13	3.35	3.89	3.36	3.02
09/24/2019	3.34	2.94	3.06	3.29	3.84	3.29	2.94
09/25/2019	3.43	3.05	3.15	3.39	3.93	3.40	3.05
09/26/2019	3.38	2.99	3.10	3.34	3.88	3.35	2.99
09/27/2019	3.38	3.00	3.10	3.33	3.88	3.34	3.00
09/30/2019	3.38	3.01	3.09	3.33	3.88	3.34	3.01
September Average	**3.42**	**3.03**	**3.14**	**3.37**	**3.91**	**3.38**	**3.03**

	IRAAID.IUSA	IRAID.IUSA	IRBAAID.IUSA	IRUTLD.IUSA	IRAAUD.IUSA	IRAUD.IUSA	IRBAAUD.IUSA
	Moody's Daily Corporate Bond Yield Averages: Aa Industrial - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: A Industrial - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: Baa Industrial - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: Average Utility - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: Aa Utility - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: A Utility - Based on bonds with maturities 20 years and above, (% p.a., NSA)	Moody's Daily Corporate Bond Yield Averages: Baa Utility - Based on bonds with maturities 20 years and above, (% p.a., NSA)
	Moody's Analytics	Moody's Analytics	Moody's Analytics	Moody's Analytics	Moody's Analytics	Moody's Analytics	Moody's Analytics
	BUSINESS	BUSINESS	BUSINESS	BUSINESS	BUSINESS	BUSINESS	BUSINESS
	United States	United States	United States	United States	United States	United States	United States
09/02/2019	na	na	na	na	na	na	na
09/03/2019	2.83	3.20	3.98	3.25	3.06	3.17	3.51
09/04/2019	2.83	3.21	3.99	3.25	3.06	3.18	3.52
09/05/2019	2.93	3.27	4.07	3.35	3.16	3.27	3.62
09/06/2019	2.90	3.24	4.03	3.32	3.13	3.24	3.58
09/09/2019	2.98	3.31	4.06	3.39	3.20	3.31	3.66
09/10/2019	3.07	3.39	4.14	3.47	3.28	3.40	3.74
09/11/2019	3.09	3.41	4.17	3.49	3.30	3.42	3.76
09/12/2019	3.13	3.45	4.21	3.54	3.35	3.47	3.81
09/13/2019	3.22	3.55	4.30	3.65	3.45	3.57	3.92
09/16/2019	3.17	3.49	4.23	3.58	3.38	3.51	3.85
09/17/2019	3.14	3.46	4.21	3.56	3.35	3.49	3.83
09/18/2019	3.10	3.42	4.17	3.52	3.31	3.45	3.79
09/19/2019	3.08	3.39	4.14	3.50	3.29	3.43	3.77
09/20/2019	3.04	3.36	4.11	3.47	3.26	3.41	3.75
09/23/2019	3.02	3.32	4.07	3.43	3.23	3.37	3.70
09/24/2019	2.94	3.26	4.02	3.38	3.17	3.31	3.65
09/25/2019	3.04	3.37	4.13	3.46	3.26	3.40	3.73
09/26/2019	3.00	3.32	4.07	3.41	3.20	3.36	3.68
09/27/2019	2.99	3.31	4.07	3.41	3.21	3.35	3.68
09/30/2019	2.97	3.31	4.07	3.41	3.21	3.35	3.69
September Average	**3.02**	**3.35**	**4.11**	**3.44**	**3.24**	**3.37**	**3.71**

Security	MOODUAVG Index	Security	MOODUAAA Index	Security	MOODUAA Index	Security	MOODUA Index	Security	MOODUBAA Index
Start Date	6/1/2019 0:00	Start Date	6/1/2019 0:00	Start Date	6/1/2019 0:00	Start Date	6/1/2019 0:00	Start Date	6/1/2019 0:00
End Date	6/30/2019 0:00	End Date	6/30/2019 0:00	End Date	6/30/2019 0:00	End Date	6/30/2019 0:00	End Date	6/30/2019 0:00
Period	D	Period	D	Period	D	Period	D	Period	D
Date	PX_LAST	Date	PX_LAST	Date	PX_LAST	Date	PX_LAST	Date	PX_LAST
6/28/2019	3.81			6/28/2019	3.52	6/28/2019	3.72	6/28/2019	4.19
6/27/2019	3.81			6/27/2019	3.53	6/27/2019	3.72	6/27/2019	4.19
6/26/2019	3.86			6/26/2019	3.57	6/26/2019	3.77	6/26/2019	4.24
6/25/2019	3.83			6/25/2019	3.53	6/25/2019	3.74	6/25/2019	4.21
6/24/2019	3.86			6/24/2019	3.58	6/24/2019	3.76	6/24/2019	4.23
6/21/2019	3.91			6/21/2019	3.64	6/21/2019	3.80	6/21/2019	4.30
6/20/2019	3.86			6/20/2019	3.58	6/20/2019	3.76	6/20/2019	4.25
6/19/2019	3.90			6/19/2019	3.61	6/19/2019	3.78	6/19/2019	4.30
6/18/2019	3.92			6/18/2019	3.64	6/18/2019	3.81	6/18/2019	4.32
6/17/2019	3.95			6/17/2019	3.67	6/17/2019	3.84	6/17/2019	4.35
6/14/2019	3.97			6/14/2019	3.69	6/14/2019	3.86	6/14/2019	4.36
6/13/2019	3.98			6/13/2019	3.69	6/13/2019	3.87	6/13/2019	4.37
6/12/2019	4.00			6/12/2019	3.72	6/12/2019	3.89	6/12/2019	4.39
6/11/2019	3.99			6/11/2019	3.72	6/11/2019	3.88	6/11/2019	4.38
6/10/2019	4.00			6/10/2019	3.73	6/10/2019	3.89	6/10/2019	4.39
6/7/2019	3.95			6/7/2019	3.67	6/7/2019	3.84	6/7/2019	4.35
6/6/2019	4.00			6/6/2019	3.73	6/6/2019	3.88	6/6/2019	4.39
6/5/2019	4.01			6/5/2019	3.74	6/5/2019	3.90	6/5/2019	4.40
6/4/2019	3.98			6/4/2019	3.71	6/4/2019	3.86	6/4/2019	4.37
6/3/2019	3.92			6/3/2019	3.65	6/3/2019	3.80	6/3/2019	4.31
June 2019									
Utility	3.93		#DIV/0!		3.65		3.82		4.31

Security	MOODUAVG Index	Security	MOODUAA Index	Security	MOODUA Index	Security	MOODUBAA Index
Start Date	5/1/2019 0:00	Start Date	5/1/2019 0:00	Start Date	5/1/2019 0:00	Start Date	5/1/2019 0:00
End Date	5/31/2019 0:00	End Date	5/31/2019 0:00	End Date	5/31/2019 0:00	End Date	5/31/2019 0:00
Period	D	Period	D	Period	D	Period	D
Date	PX_LAST	Date	PX_LAST	Date	PX_LAST	Date	PX_LAST
5/31/2019	3.95	5/31/2019	3.68	5/31/2019	3.83	5/31/2019	4.33
5/30/2019	4.00	5/30/2019	3.75	5/30/2019	3.87	5/30/2019	4.38
5/29/2019	4.02	5/29/2019	3.77	5/29/2019	3.88	5/29/2019	4.41
5/28/2019	4.03	5/28/2019	3.76	5/28/2019	3.91	5/28/2019	4.42
5/24/2019	4.08	5/24/2019	3.81	5/24/2019	3.95	5/24/2019	4.47
5/23/2019	4.05	5/23/2019	3.79	5/23/2019	3.93	5/23/2019	4.43
5/22/2019	4.12	5/22/2019	3.86	5/22/2019	4.00	5/22/2019	4.50
5/21/2019	4.14	5/21/2019	3.89	5/21/2019	4.01	5/21/2019	4.51
5/20/2019	4.13	5/20/2019	3.88	5/20/2019	4.00	5/20/2019	4.50
5/17/2019	4.11	5/17/2019	3.85	5/17/2019	3.99	5/17/2019	4.48
5/16/2019	4.12	5/16/2019	3.87	5/16/2019	4.00	5/16/2019	4.49
5/15/2019	4.11	5/15/2019	3.85	5/15/2019	3.99	5/15/2019	4.48
5/14/2019	4.13	5/14/2019	3.89	5/14/2019	4.01	5/14/2019	4.50
5/13/2019	4.12	5/13/2019	3.86	5/13/2019	3.99	5/13/2019	4.50
5/10/2019	4.13	5/10/2019	3.88	5/10/2019	4.01	5/10/2019	4.51
5/9/2019	4.13	5/9/2019	3.88	5/9/2019	4.02	5/9/2019	4.50
5/8/2019	4.14	5/8/2019	3.88	5/8/2019	4.03	5/8/2019	4.50
5/7/2019	4.09	5/7/2019	3.82	5/7/2019	3.99	5/7/2019	4.45
5/6/2019	4.13	5/6/2019	3.87	5/6/2019	4.03	5/6/2019	4.49
5/3/2019	4.14	5/3/2019	3.88	5/3/2019	4.05	5/3/2019	4.50
5/2/2019	4.15	5/2/2019	3.88	5/2/2019	4.06	5/2/2019	4.51
5/1/2019	4.12	5/1/2019	3.85	5/1/2019	4.03	5/1/2019	4.48
May Avg Utility Average	**4.10**		**3.84**		**3.98**		**4.47**

Security	MOODUAVG Index	Security	MOODUAA Index	Security	MOODUA Index	Security	MOODUBAA Index
Start Date	4/1/2019 0:00	Start Date	4/1/2019 0:00	Start Date	4/1/2019 0:00	Start Date	4/1/2019 0:00
End Date	4/30/2019 0:00	End Date	4/30/2019 0:00	End Date	4/30/2019 0:00	End Date	4/30/2019 0:00
Period	D	Period	D	Period	D	Period	D
Date	PX_LAST	Date	PX_LAST	Date	PX_LAST	Date	PX_LAST
4/30/2019	4.14	4/30/2019	3.87	4/30/2019	4.05	4/30/2019	4.49
4/29/2019	4.16	4/29/2019	3.89	4/29/2019	4.08	4/29/2019	4.51
4/26/2019	4.13	4/26/2019	3.86	4/26/2019	4.04	4/26/2019	4.49
4/25/2019	4.16	4/25/2019	3.89	4/25/2019	4.06	4/25/2019	4.52
4/24/2019	4.16	4/24/2019	3.89	4/24/2019	4.06	4/24/2019	4.52
4/23/2019	4.19	4/23/2019	3.92	4/23/2019	4.09	4/23/2019	4.55
4/22/2019	4.21	4/22/2019	3.94	4/22/2019	4.11	4/22/2019	4.58
4/18/2019	4.18	4/18/2019	3.91	4/18/2019	4.08	4/18/2019	4.55
4/17/2019	4.21	4/17/2019	3.93	4/17/2019	4.11	4/17/2019	4.58
4/16/2019	4.22	4/16/2019	3.96	4/16/2019	4.12	4/16/2019	4.59
4/15/2019	4.20	4/15/2019	3.93	4/15/2019	4.10	4/15/2019	4.56
4/12/2019	4.21	4/12/2019	3.95	4/12/2019	4.11	4/12/2019	4.57
4/11/2019	4.19	4/11/2019	3.91	4/11/2019	4.09	4/11/2019	4.56
4/10/2019	4.16	4/10/2019	3.89	4/10/2019	4.06	4/10/2019	4.53
4/9/2019	4.17	4/9/2019	3.89	4/9/2019	4.07	4/9/2019	4.54
4/8/2019	4.19	4/8/2019	3.91	4/8/2019	4.09	4/8/2019	4.56
4/5/2019	4.17	4/5/2019	3.89	4/5/2019	4.08	4/5/2019	4.55
4/4/2019	4.18	4/4/2019	3.90	4/4/2019	4.09	4/4/2019	4.56
4/3/2019	4.20	4/3/2019	3.92	4/3/2019	4.10	4/3/2019	4.58
4/2/2019	4.16	4/2/2019	3.88	4/2/2019	4.05	4/2/2019	4.54
4/1/2019	4.16	4/1/2019	3.88	4/1/2019	4.06	4/1/2019	4.55
Utility							
April 2019	**4.18**		**3.91**		**4.08**		**4.55**

```
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Initializing NLOGIT Version 4.0.1 (January 1, 2007).
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Initializing NLOGIT Version 4.0.1 (January 1, 2007).
--> READ
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   ;FILE=F:\rra.XLS
   ;LABELS=1$
--> REGRESS;LHS=RP;RHS=ONE,INT;AR1$

+----------------------------------------------------+
| Ordinary    least squares regression                |
| Model was estimated Sep 20, 2019 at 03:09:06PM      |
| LHS=RP      Mean                 =  .3597641E-01    |
|             Standard deviation   =  .1631405E-01    |
| WTS=none    Number of observs.   =        154       |
| Model size  Parameters           =          2       |
|             Degrees of freedom   =        152       |
| Residuals   Sum of squares       =  .3884833E-02    |
|             Standard error of e  =  .5055503E-02    |
| Fit         R-squared            =  .9045980        |
|             Adjusted R-squared   =  .9039704        |
| Model test  F[  1,   152] (prob) =1441.26 (.0000)   |
| Diagnostic  Log likelihood       =  596.7308        |
|             Restricted(b=0)      =  415.8073        |
|             Chi-sq [  1]  (prob) = 361.85 (.0000)   |
| Info criter. LogAmemiya Prd. Crt. = -10.56165       |
|             Akaike Info. Criter. = -10.56165        |
| Autocorrel  Durbin-Watson Stat.  =  .7724301        |
|             Rho = cor[e,e(-1)]   =  .6137849        |
+----------------------------------------------------+
+--------+--------------+----------------+--------+--------+----------+
|Variable| Coefficient  | Standard Error |t-ratio |P[|T|>t]| Mean of X|
+--------+--------------+----------------+--------+--------+----------+
 Constant|   .07331475      .00106455     68.869   .0000
 INT     |  -.46767318      .01231889    -37.964   .0000    .07983853


+---------------------------------------------+
| AR(1) Model:    e(t) = rho * e(t-1) + u(t)  |
| Initial value of rho       =       .61378   |
| Maximum iterations         =          100   |
| Method = Prais - Winsten                    |
| Iter=  1, SS=      .002, Log-L= 632.988647  |
| Iter=  2, SS=      .002, Log-L= 633.107874  |
| Iter=  3, SS=      .002, Log-L= 633.115904  |
| Iter=  4, SS=      .002, Log-L= 633.116047  |
| Iter=  5, SS=      .002, Log-L= 633.115763  |
| Final value of Rho    =            .654148  |
| Iter=  5, SS=      .002, Log-L= 633.115763  |
| Durbin-Watson:  e(t) =             .691704  |
| Std. Deviation:  e(t) =            .005268  |
| Std. Deviation:  u(t) =            .003984  |
| Durbin-Watson:  u(t) =            2.181288  |
| Autocorrelation: u(t) =           -.090644  |
```

| N[0,1] used for significance levels |

Variable	Coefficient	Standard Error	b/St.Er.	P[|Z|>z]	Mean of X
Constant	.07662705	.00229258	33.424	.0000	
INT	-.51022347	.02626424	-19.427	.0000	.07983853
RHO	.65414779	.06114863	10.698	.0000	

Railroad Commission Rate of Return Decisions Since GUD No. 9400 (2004)

GUD No.	Utility Name	Debt	Other	Equity	Cost of Debt	Other	Return on Equity	Rate of Return	Date Approved
9400	TXU Gas Co. *Cost of Preferred Securities	48.300%	*1.900%	49.800%	6.570%	*5.510%	10.000%	8.258%	5/25/2004
9465	Texas Gas Service Co. - South Jefferson	46.500%		53.500%	6.250%		10.300%	8.420%	6/15/2004
9469	CenterPoint Energy Entex - Houston *•Not specified under "Black Box" settlement terms*							8.270%	6/8/2004 ***Settlement***
9533	CenterPoint Energy Entex - South Texas *Cost of Preferred Securities	50.100%	*0.040%	49.860%	6.790%	*4.900%	11.250%	9.010%	4/5/2005
9534	CenterPoint Energy Entex - Beaumont/East Tx *Cost of Preferred Securities	50.100%	*0.040%	49.860%	6.790%	*4.900%	11.250%	9.010%	4/5/2005
9620	Aransas Natural Gas	0.00%		100.00%	0.00%		13.250%	13.250%	2/19/2006
9670	Atmos Energy Mid-Tex	51.900%		48.100%	5.960%		10.000%	7.903%	3/29/2007
9713	Greenlight Gas	48.220%		51.780%	7.23%		8.000%	7.630%	4/10/2007
9731	Hughes Natural Gas	0.00%		100.00%	0.00%		10.25%	10.25%	11/16/2007
9762	Atmos Energy Corp., Mid-Tex Division	51.730%		48.270%	6.100%		10.000%	7.980%	6/29/2008
9770	Texas Gas Service Company - South Texas *Cost of Preferred Securities	45.100%	*0.200%	54.700%	6.290%	*4.700%	10425%	8.551%	4/24/2008
9791	CenterPoint Energy Entex - Texas Coast	44.600%		55.400%	7.239%		10.060%	8.802%	10/20/2008
9797	Universal Natural Gas Inc *Short-Term Debt	67.780%	*3.870%	28.340%	9.650%	*4.700%	12.500%	10.240%	12/16/2008
9799	Si Energy, LP *Preferred Equity	45.100%	*0.200%	54.700%	6.290%	*4.700%	11.000%	8.867%	11/12/2008
9810	Bluebonnet Natural Gas LLC	66.600%		33.400%	7.650%		12.500%	9.270%	11/6/2008
9837	LDC, LLC	44.910%		55.090%	7.500%		8.500%	8.051%	7/14/2009
9839	Texas Gas Service Company - North Texas	49.000%		51.000%	6.220%		10.850%	8.5840%	4/28/2009
9852	Zia Natural Gas Company	47.500%		52.500%	6.100%		10.270%	8.290%	4/14/2009
9869	Atmos Energy Corp., Mid-Tex Division	51.090%		48.910%	6.880%		10.400%	8.600%	2/23/2010
9902	CenterPoint Energy Entex - Houston	44.400%		55.600%	6.334%		10.500%	8.650%	2/23/2010
9988	Texas Gas Service - El Paso	40.760%		59.240%	6.210%		10.330%	8.650%	10/14/2010
10000	Atmos Pipeline - Texas	49.500%		50.500%	6.870%		11.800%	9.361%	6/27/2011
10020	Greenlight Gas	55.140%		44.860%	7.232%		8.000%	7.630%	4/18/2011

GUD No.	Utility Name	Debt	Equity	Cost of Debt	Return on Equity	Rate of Return	Date Approved	
10038	CenterPoint Energy Entex - South Texas	44.560%	55.440%	7.134%	10.050%	8.750%	4/18/2011	***Settlement***
10041	Atmos Energy Corp., West Texas Division	49.900%	50.100%	6.870%	10.700%	8.790%	7/2612011	
10069	Texas Gas Service Company - El Paso	40.760%	59.240%	6.210%	10.330%	8.650%	6/27/2011	
10084	Atmos Energy West Texas (Lubbock) *•Not specified under "Black Box• settlement terms*			6.870%		8.720%	11/8/2011	***Settlement***
10085	Atmos Energy West Texas Division *•Not specified under "Black Box• settlement terms*			6.870%		8.720%	11/8/2011	***Settlement***
10170	Atmos Mid-Tex	48.310%	51.690%	6.500%	10.500%	8.570%	12/4/2012	
10174	Atmos West Texas	48.310%	51.690%	6.500%	10.500%	8570%	12/4/2012	
10182	CenterPoint Energy Entex – Beaumont/East Tx	42.000%	58.000%	6.460%	10.000%	8.510%	12/4/2012	***Settlement***
10190	Hughes Natural Gas Inc.	44.500%	55.500%	7.000%	10.600%	9.000%	3/23/2013	***Settlement***
10196	Bluebonnet Natural Gas	48.000%	52.000%	7.650%	10.250%	9.000%	12/4/2012	
10217	Texas Gas Service – South Texas	42.000%	58.000%	6.161%	10.330%	8.579%	3/26/2013	***Settlement***
10235	West Texas Gas	50.000%	50.000%	5.320%	10.500%	7.910%	6/13/2013	***Settlement***
10238	Onalaska Water & Gas Supply	45.000%	55.000%	7.000%	10.500%	8.930%	8/6/2013	***Settlement***
10285	Texas Gas Service – RGV	44.610%	55.390%		10.330%	8.0845%	11/26/2013	***Settlement***
10432	CenterPoint Energy Entex – Texas Coast	45.500%	54.500%	6.114%	10.000%	8.230%	8/25/2015	***Settlement***
10488	Texas Gas Service–Gulf Coast	39.796%	60.204%	3.950%	9.500%	7.291%	5/3/2016	***Settlement***
10506	Texas Gas Service – El Paso	39.900%	60.100%	3.950%	9.500%	7.280%	9/27/2016	
10526	Texas Gas Service – CTCSA	39.50%	60.50%	3.950%	9.500%	7.308%	11/15/2016	***Settlement***
10567	CenterPoint Energy Entex – Houston/Tx Coast	44.850%	55.150%	6.0853%	9.6000%	8.0237%	5/23/2017	***Settlement***
10580	Atmos Pipeline – Texas Includes Short-Term Debt	47.360%	52.640%	5.950%	11.500%	8.870%	8/1/2017	
10622	LDC, LLC	50.00%	50.00%	6.43%	9.50%	7.965%	9/19/2017	***Settlement***
10640	Atmos Energy – Mid-Tex (DARR)	41.49%	58.51%	5.95%	10.1%	8.38%	12/5/2017	
10656	Texas Gas Service - RGV	38.71%	61.29%	3.940%	9.50%	7.35%	3/20/2018	***Settlement***
10669	CenterPoint Energy Entex-South TX Division	45.00%	55.00%	6.0480%	9.8000%	8.1116%	5/22/2018	***Settlement***
10679	SiEnergy, LP Capital Structure Not Specified							***Settlement***

GUD No.	Utility Name	Debt	Equity	Cost of Debt	Return on Equity	Rate of Return	Date Approved	
10739	Texas Gas Service – NTSA	37.84%	62.16%	3.94%	9.75%	7.55%	11/13/18	***Settlement***
10742	Atmos Mid-Tex	39.82%	60.18%	5.20%	9.80%	7.97%	12/11/18	***Settlement***
10743	Atmos West Texas	39.82%	60.18%	5.20%	9.80%	7.97%	12/11/2018	***Settlement***
10766	Texas Gas Service – BSSA	37.84%	62.16%	3.94%	9.75%	7.55%	02/05/2019	***Settlement***
10779	Atmos Mid-Tex	39.82%	60.18%	5.2%	9.8%	7.97%	05/21/2019	***Settlement***

Notes: This compilation includes rate filing dockets both litigated and settled where a rate of return (ROR) was specified. Dockets resolved through settlement agreements are indicated, and otherwise were litigated.