WTG

July 16, 2024

Via Federal Express

To the Honorable Mayors and Council Members:

Attached is a copy of the Statement of Intent of West Texas Gas Utility, LLC ("WTGU" or the "Company"), to increase gas utility rates within the incorporated areas of the Cities of Amarillo, Balmorhea, Cactus, Canadian, Canyon, Claude, Dalhart, Darrouzett, Devine, Eden, Farwell, Follett, Groom, Higgins, Junction, Kermit, La Vernia, Lockhart, Lubbock, Luling, Menard, Miami, Mobeetie, Natalia, Paint Rock, Seguin, Shamrock, Somerset, Sonora, Stratford, Texhoma, Texline, Van Horn, Wheeler, White Deer and Wolfforth, Texas ("Cities"). WTGU is filing a Statement of Intent at this time to more accurately match base rates with the costs of providing service and to recover extraordinary gas costs related to Winter Storm Uri through a separate surcharge. The Company requests that the proposed rates and tariffs contained in the Statement of Intent become effective on August 20, 2024, which is 35 days from the date of this filing. No action on the part of the Cities is required to permit the Company's proposed rates to take effect.

In addition to 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 seventy-three Counties in Texas that WTGU serves. The Company is requesting that the Cities and the Commission approve the same rates and tariffs and is providing the same information, including written testimony, to the Cities it serves and to the Commission.

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

Best regards,

J.J. King
Vice President of Gas Marketing

JJK:eas
Attachment

cc: Amanda Edgmon, Treasurer/Secretary, West Texas Gas Utility, LLC
Kate Norman, Coffin Renner LLP

STATEMENT OF INTENT OF WEST TEXAS GAS UTILITY, LLC TO INCREASE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF TEXAS

To All Cities Within the State of Texas Served by West Texas Gas Utility, LLC:

West Texas Gas Utility, LLC ("WTGU" or "the Company"), a "gas utility" under Gas Utility Regulatory Act ("GURA")[1] § 101.003(7), respectfully files this Statement of Intent, pursuant to Subchapter C of Chapter 104 of GURA and the rules of the Gas Services Department of the Railroad Commission of Texas ("Commission"), to increase gas utility rates within the unincorporated areas within Andrews, Archer, Armstrong, Atascosa, Bailey, Bastrop, Bexar, Brewster, Briscoe, Brown, Caldwell, Carson, Castro, Cochran, Coleman, Collingsworth, Concho, Crosby, Culberson, Dallam, Dawson, Deaf Smith, Dimmit, Donley, Floyd, Frio, Gaines, Gray, Hale, Hall, Hansford, Hartley, Hemphill, Hockley, Hutchinson, Jeff Davis, Kimble, Kinney, La Salle, Lamb, Lipscomb, Lubbock, Lynn, McCulloch, Martin, Mason, Maverick, Medina, Menard, Moore, Ochiltree, Oldham, Parmer, Pecos, Potter, Presidio, Randall, Reeves, Roberts, Runnels, Sherman, Sutton, Swisher, Terry, Tom Green, Travis, Uvalde, Val Verde, Wheeler, Wilson, Winkler, Yoakum, and Zavala Counties.[2] WTGU's natural gas service area also includes the Cities of Amarillo, Balmorhea, Cactus, Canadian, Canyon, Claude, Dalhart, Darrouzett, Devine, Eden, Farwell, Follett, Groom, Higgins, Junction, Kermit, La Vernia, Lockhart, Lubbock, Luling, Menard, Miami, Mobeetie, Natalia, Paint Rock, Seguin, Shamrock, Somerset, Sonora, Stratford, Texhoma, Texline, Van Horn, Wheeler, White Deer, and Wolfforth, Texas. The Company's proposed rates were developed based on WTGU's costs to serve customers in the entirety of its Texas service area that take service under rate schedule tariffs approved by either a municipality or the Commission ("Jurisdictional Customers"). Contemporaneously with this filing, WTGU is also filing a Statement of Intent to Increase Rates for Jurisdictional Customers within each of the municipalities served by WTGU.

The Company requests that the proposed tariffs, attached as **Exhibit A** to this Statement of Intent and incorporated herein by reference, become effective on August 20, 2024, which is 35

[1] Tex. Util. Code §§ 101.001 *et seq*.
[2] This pleading uses the terms "unincorporated areas" and "environs" interchangeably.

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

WTGU is proposing new rates for the jurisdictional service it provides in Texas based on the cost of providing service to all Jurisdictional Customers within its service area, inclusive of both incorporated and unincorporated areas served by WTGU.[3] This approach is consistent with the system-wide rates that are currently in effect for WTGU. For the 12-month period ended December 31, 2023, the Company's overall jurisdictional base rate revenue requirement on a system-wide basis totaled approximately $26,466,131. The total adjusted revenue WTGU currently receives from jurisdictional customers is approximately $13,188,368, leaving a revenue deficiency of approximately $13,277,763. However, to moderate the effect of WTGU's rate change request on its customers, WTGU is not requesting to recover its full jurisdictional cost of service through this Statement of Intent. Rather, WTGU is requesting a base rate revenue requirement on a jurisdictional, system-wide basis of approximately $19,967,258.

If approved, the requested rates will increase WTGU's jurisdictional revenues in Texas by $6,778,890 which is an increase of approximately 35.75% total revenues including gas costs, or 51.40% base rate revenues, which excludes gas costs. Because the proposed changes will increase WTGU's total aggregate revenues by more than 2.5%, the proposed rate change constitutes a "major change" in rates as that term is defined by GURA § 104.101. Additionally, regarding GURA § 104.006, the proposed rates for areas not within a municipality 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) a prudence determination for all used and useful capital investment WTGU has made through December 31, 2023, including all capital investment reflected in the Company's interim rate adjustment ("IRA") filings made since WTGU's last statement of intent proceeding, pursuant to GURA § 104.301; (2) approval of a

[3] WTGU serves domestic and non-domestic jurisdictional customers and irrigation and agricultural non-jurisdictional customers. Domestic customers are residential customers. Non-domestic customers are all other jurisdictional customers.

51.22% allocation factor for capital investment costs that should be allocated to or recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers to be used in future IRA filings; (3) Commission approval of new depreciation rates; (4) Commission approval of a regulatory asset comprised of extraordinary gas costs related to WTGU's continuation of service during Winter Storm Uri; (5) recovery of the Winter Storm Uri regulatory asset through a monthly surcharge over 60 months; (6) approval of its tariffs contained in Exhibit A; and (7) approval of a rate case expense recovery surcharge to recover the reasonable rate case expenses associated with this filing through a surcharge on rates, as provided by law. The exact amount of rate case expense will not be known until the case is complete.

The 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 Company is proposing revised tariffs for natural gas service that will include rates for domestic and non-domestic customers that will consist of a customer charge and a volumetric charge. Implementation of new tariffs necessarily entails withdrawal of the Company's existing incorporated and environs tariffs. Other tariff changes are detailed in Section III(F) below.

II. JURISDICTION

WTGU is a gas utility as that term is defined in GURA § 101.003(7). Pursuant to GURA § 102.001(a), the Commission has exclusive original jurisdiction to set the rates WTGU requests for Jurisdictional Customers in the unincorporated areas served by WTGU. Consistent with such jurisdiction, the proposed rates identified in Exhibit A are applicable to the Company's natural gas service within the unincorporated areas. The Commission also has appellate authority over municipalities exercising original jurisdiction over the Company's filings.

III. DETAILS OF PROPOSED CHANGES

A. Rate Filing Package

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

- Exhibit A — Proposed Tariffs
- Exhibit B — Proposed Revenue Change by Class
- Exhibit C — Average Bill Impact by Class

- Exhibit D Direct Testimony and Exhibits
- Exhibit E Proposed Notice
- Exhibit F Protective Agreement
- Exhibit G Cost of Service Schedules
- Exhibit H Workpapers

B. Test Year

The Company's proposed cost of service as set forth in this Statement of Intent and Rate Filing Package is based on the 12-month period ended December 31, 2023.

C. Class and Number of Customers Affected

The proposed changes to the Company's tariffs will affect all Jurisdictional Customers that WTGU serves in Texas. The table below shows the approximate number of customers by class, who will be affected by the proposed rate changes:

Table 1
Customer Classes Affected

Customer Class	Environs Customers	Incorporated Customers
Domestic[4]	5,747	12,176
Non-Domestic[5]	475	2,010

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.

D. Proposed Rate Change

The proposed changes to rates for jurisdictional customers are set out below:

[4] A "domestic customer" typically refers to residential service and is one whose natural gas service is individually metered.
[5] A "non-domestic customer" is a customer who is not taking service under the residential tariff and includes commercial, industrial customers, public authority customers, and non-profit customers.

Table 2
Comparison of Current Rates to Proposed Rate Change[6]

Domestic Customers		
	Current	**Proposed**
Customer Charge	$23.42 per month	$29.50 per month
All Consumption[7]	$4.84 per Mcf	$7.68 per Mcf
Non-Domestic Customers		
	Current	**Proposed**
Customer Charge	$43.57 per month	$79.00 per month
All Consumption	$2.69 per Mcf	$4.89 per Mcf

Exhibit C shows the average bill impact by customer class.

E. Depreciation Rates

The Company requests that the Commission approve new depreciation rates for WTGU and all of its natural gas assets.

F. Other Proposed Tariff Changes

In addition to the proposed changes in rates, WTGU proposes to add a new Winter Storm Cost Recovery Rider to recover approximately $3.5 million over a five-year period. The Company also proposes to remove the EDIT Credit Rider because the credit associated with that rider is complete and to make non-substantive changes to the Pipeline Safety Fee Rider. The Company also proposes non-substantive formatting changes to its tariffs. WTGU does not propose to change the fee, deposit, or general terms of service provisions in the tariffs.

G. Effective Date

The Company requests that the Commission order the proposed rates to be effective for bills rendered on and after August 20, 2024, which is 35 days after the filing date.

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[6] The current rate amounts include amounts for the Company's pending GRIP filing in Case No. 00017395.
[7] The terms "All Consumption" and "Volumetric" are used interchangeably.

H. 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:

- *Jack J. ("J.J.") King*, Vice President of Gas Marketing, provides an overview of the Company's operations, service territory, customer base and rate filing; supports the prudence of the Company's capital investment; explains affiliate relationships and transactions; addresses certain expense items; addresses extraordinary costs incurred during the Company's response to Winter Storm Uri; and identifies the tariff changes WTGU is requesting.
- *Amanda Edgmon*, Treasurer/Secretary also serving as WTGU Regulatory Accountant, addresses the Company's books and records; attests to the financial information contained in the Company's schedules; sponsors the Company's Gas Reliability Infrastructure Program ("GRIP") filings; discusses the proposed change to the factor to be used in future GRIP filings to determine the amount of capital investment that should be allocated to or recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers; presents the calculation of the regulatory asset amounts related to Winter Storm Uri; and explains the corporate cost allocation method and services from some affiliates.
- *Matthew S. Smith, P.E.*, Associate Vice President of Operations, provides an overview of field operations and expenses and supports the Company's rationale for its request to modify the factor used to determine what portion of the Company's capital investment will be recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers.
- *Dane A. Watson*, with Alliance Consulting Group, sponsors the depreciation study that he performed that produces the depreciation rates used to determine the Company's depreciation expense.
- *Dr. Bruce H. Fairchild*, Principal with Financial Concepts and Applications, Inc., sponsors the Company's cost of service schedules, requested capital structure and return on equity, overall rate of return, billing determinants, income tax expense and other tax issues, cost allocation and rate design; and presents the Company's proposed method for direct assignment of costs attributable to Jurisdictional Customers and Non-Jurisdictional Customers.

IV. RATE CASE EXPENSES

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

V. PUBLIC NOTICE

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

VI. COMPANY REPRESENTATIVES FOR NOTIFICATION

WTGU's authorized representatives are:

J.J. King, Vice President- Gas Marketing
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and

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

VII. 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, WTGU attaches as **Exhibit F** to this Statement of Intent a Protective Agreement to be used in this case. WTGU will provide confidential material upon execution of Exhibit A attached to the Protective Agreement.

VIII. CONCLUSION

WTGU requests that: (1) rates are approved consistent with those proposed herein to become effective for bills rendered on and after August 20, 2024; (2) capital investment WTGU has made through December 31, 2023 is deemed prudent; (3) the Commission approve the use of a 51.22% allocation factor for capital investment costs that should be allocated to or recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers to be used in future IRA filings; (4) the Commission approve new depreciation rates; (5) the proposed tariffs be approved; (6) the Commission approve the requested regulatory asset amount for costs related to Winter Storm Uri; (7) the Commission approve recovery of the Winter Storm Uri regulatory asset amount through a monthly surcharge over 60 months; (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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ATTORNEYS FOR WEST TEXAS GAS UTILITY, LLC

COMMERCIAL SERVICE RATE - ENVIRONS

APPLICABILITY

Applicable to all commercial customers and to customers not otherwise specifically provided for under any other rate schedule or served under a contract in an unincorporated or environs area served by West Texas Gas Utility, LLC ("WTGU"). This rate is only available to full requirements customers of WTGU.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Commercial consumers and to consumers not otherwise specifically provided for under any other rate schedule or served under a contract per meter billing cycle or for any part of a billing cycle for which gas service is available at the same location.

Customer Charge	$79.00
All Consumption @	$4.89 per Mcf

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

OTHER FEES

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 Gas Cost Adjustment-ENV.

Rate Case Expense Rider: 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.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-ENV.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provisions of Rate Schedule MISCFEES-ENV.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-ENV.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

Effective: ____________

GAS COST ADJUSTMENT – ENVIRONS

Applicability

This clause shall apply to all customers served by WTGU, except for customers purchasing gas at contract rates. Each customer's gas costs will be determined by the costs incurred in the applicable Gas Cost Zone. For purposes of determining gas purchase costs, all customers will be located in one of three Gas Cost Zones: North, South, and West. Each Gas Cost Zone consists of the following systems or geographic areas:

NORTH GAS COST ZONE:
Unincorporated areas of the Counties of Armstrong, Carson, Collingsworth, Dallam, Deaf Smith, Donley, Gray, Hall, Hansford, Hartley, Hemphill, Hutchinson, Lipscomb, Moore, Ochiltree, Oldham, Potter, Randall, Roberts, Sherman and Wheeler.

SOUTH GAS COST ZONE:
Unincorporated areas of the Counties of Atascosa, Bastrop, Bexar, Brown, Caldwell, Coleman, Concho, Dimmitt, Frio, Kimble, Kinney, La Salle, Mason, Maverick, McCulloch, Medina, Menard, Runnels, Sutton, Tom Green, Travis, Uvalde, Val Verde, Wilson, and Zavala.

WEST GAS COST ZONE:
Unincorporated areas of the Counties of Andrews, Archer, Bailey, Brewster, Briscoe, Castro, Cochran, Crosby, Culberson, Dawson, Floyd, Gaines, Hale, Hockley, Jeff Davis, Lamb, Lubbock, Lynn, Martin, Parmer, Pecos, Presidio, Reeves, Swisher, Terry, Winkler and Yoakum.

Intent

This clause is intended to allow collection of West Texas Gas Utility, LLC's ("WTGU") gas purchase costs in a manner that will lessen monthly fluctuations in the gas cost factor and ensure that all amounts billed to customers are fully reconciled with actual costs incurred, subject to limitations for excessive lost and unaccounted for gas.

Definitions

Gas Cost Zones – North, South, and West, as defined in the "Applicability" section below.

Interest – The percentage of interest shall be the interest rate established by the Public Utility Commission, or such other agency or manner as determined by the Commission, under Chapter 183 of the Texas Utilities Code.

Lost and Unaccounted For Gas – Lost and Unaccounted for Gas (LUG) shall represent volumes of gas metered into the distribution system and volumes of gas metered out of the distribution system at 14.65 p.s.i.a., which shall include distribution and non-distribution volumes. WTGU transmission LUG shall not be included in these volumes.

Purchased Gas Costs –The total cost of Purchase Volumes, as received into the Company's distribution systems within each Gas Cost Zone.

Purchased Gas Factor ("PGF") – A factor on each customer's monthly bill, expressed in dollars per Mcf, to reflect the Purchase Gas Costs, all as more specifically described herein.

Purchase/Sales Ratio – A ratio determined by dividing the Company's Purchase Volumes metered into the distribution system during the twelve-month period ending June 30 of each year by the sum of the Company's Sales Volumes metered out of the distribution system, volumes of metered Company used gas, and losses of gas from the Company's systems within each Gas Cost Zone that have been billed to third parties during the same period. Such ratio as determined shall in no event exceed 1.0526 i.e. 1/1(1-.05) unless expressly authorized by the applicable regulatory authority.

Purchase Volumes – The volumes of gas, expressed in Mcf's and stated at 14.65 psia, received by the Company's distribution system from all sources within each Gas Cost Zone, including monthly purchases and withdrawals from storage, if any, for use by general service customers. This quantity of gas shall not include LUG attributable to the WTGU Transmission System or transmission function.

Reconciliation Amount – The net of any monthly imbalances by Gas Cost Zone during the period covered by the Reconciliation Review.

Reconciliation Component – The monthly amount to be refunded or passed through to customers within each Gas Cost Zone, consisting of one-twelfth of the Reconciliation Amount.

Reconciliation Factor – A factor, expressed as a cost per Mcf on customer bills within each Gas Cost Zone, reflecting the customer's share of the Reconciliation Component applicable to the period covered by the bill.

Reconciliation Review – An annual review of the Company's records covering each 12-month period ending June 30 to determine any imbalances between the Purchase Gas Cost and the Sales Amount as applied to each Gas Cost Zone during that period.

Sales Amount – Sales Volumes, volumes of metered Company used gas, and losses of gas from the Company's system within each Gas Cost Zone that have been billed to third parties, multiplied by the Purchased Gas Factor.

Sales Volumes – The volumes of gas metered to general service customers within each Gas Cost Zone expressed in Mcf's and stated at 14.65 psia.

Weighted Average Cost of Gas – The Purchase Gas Costs invoiced by third parties divided by the Purchase Volumes, calculated on a monthly basis for each Gas Cost Zone.

Purchase Gas Cost Component (PGC)

The Purchase Gas Cost for each Gas Cost Zone shall be computed utilizing the following components for the distribution system customers:

- Cost of gas purchased
- Credits, Refunds or Out of Period adjustments
- Cost of gas withdrawn from storage
- Interest on storage gas withdrawn
- Upstream Gathering and Transportation Charges
- Storage Deliverability Charges
- Storage Capacity Charges
- New taxes on the purchased gas or the purchase transaction and not reflected on elsewhere on customer bills

WTGU shall keep accurate records of all storage gas purchases, including the date, quantity, cost, and associated expenses. WTGU shall account for storage gas purchases and withdrawals using a weighted average cost basis.

Purchased Gas Factor (PGF) Calculation

Each customer bill shall include a Purchased Gas Factor reflecting the estimated Weighted Average Cost of Gas, plus additional elements described in this section, during the period covered by the bill for each Gas Cost Zone. The PGF shall be determined to the nearest $0.001 per Mcf, and the following provisions shall apply:

- In addition to the estimated weighted average cost of gas for the current month's billing period, the PGF may include a pro rata portion of an amount reflecting the difference between the estimated Weighted Average Cost of Gas and the actual Weighted Average Cost of Gas during the previous billing period for each Gas Cost Zone
- The PGF shall also include a "Reconciliation Factor," an amount reflecting the customer's share of any gas cost imbalances in the preceding reconciliation period for each Gas Cost Zone.
- The PGF factor may also include an amount reflecting any new taxes or levies specifically applied to gas costs or purchases and not otherwise reflected on the customer bill for each Gas Cost Zone.

The Purchased Gas Factor is expressed as a formula as follows:

$$(A+/-B) + C + D = E$$

Where:

A = Estimated WACOG
B = Est. WACOG/Act. WACOG Difference
C = Reconciliation Factor
D = New Taxes
E = Total PGF

Gas Cost Reconciliation (GCR)

WTGU shall keep accurate books and records of the Reconciliation Review, monthly Purchased Gas Factor reports to the Railroad Commission of Texas, and shall account for the Reconciliation Component and the Reconciliation Factors for each Gas Cost Zone.

A Reconciliation Review and calculation shall first determine whether the lost and unaccounted for gas is more or less than 5% of that metered into the system. The sales volumes shall be converted to the same pressure base as the purchase volumes. Calculations of the sales volumes furnished to its gas sales customers (from meters not corrected for pressure and/or temperature) shall be calculated utilizing the following service pressures (psia):

Unincorporated areas of the Counties of:

Andrews	13.45	Frio	14.68	Ochiltree	13.78
Archer	13.45	Gaines	13.45	Oldham	13.45
Armstrong	13.38	Gray	13.78	Parmer	13.18
Atascosa	14.68	Hale	13.45	Pecos	13.68
Bailey	13.45	Hall	13.45	Potter	13.45
Bastrop	14.68	Hansford	13.78	Presidio	13.48
Bexar	14.68	Hartley	13.07	Randall	13.45
Brewster	13.48	Hemphill	13.88	Reeves	13.48
Briscoe	13.45	Hockley	13.45	Roberts	13.68
Brown	14.08	Hutchinson	13.68	Runnels	14.28
Caldwell	14.68	Jeff Davis	13.48	Sherman	13.18
Carson	13.38	Kimble	14.18	Sutton	13.98
Castro	13.45	Kinney	14.68	Swisher	13.45
Cochran	13.45	LaSalle	14.68	Terry	13.45
Coleman	14.08	Lamb	13.45	Tom Green	14.28
Collingsworth	13.38	Lipscomb	13.78	Travis	14.68
Concho	14.08	Lubbock	13.45	Uvalde	14.68
Crosby	13.45	Lynn	13.45	Val Verde	14.68
Culberson	13.48	Martin	13.45	Wheeler	13.78
Dallam	13.07	Mason	14.08	Wilson	14.68
Dawson	13.45	Maverick	14.68	Winkler	13.68
Deaf Smith	13.45	McCulloch	14.08	Yoakum	13.45
Dimmitt	14.68	Medina	14.68	Zavala	14.68
Donley	13.38	Menard	14.08		
Floyd	13.45	Moore	13.28		

If the Reconciliation Review indicates a gas loss or gas gain of less than 5% of that metered into the system, the following methodology shall apply:

- WTGU shall calculate the imbalance between its Net Jurisdictional Cost of Gas and amount collected through the PGA billed on a monthly basis for said Gas Cost Zone. The Net Jurisdictional Cost of Gas shall be calculated by multiplying the Total Jurisdictional Sales

Volumes by the Actual P/S Ratio to arrive at the Calculated Purchased Volume. The Calculated Purchased Volume is then multiplied by the WACOG to arrive at the Net Jurisdictional Cost of Gas.

- Interest shall be applied to each monthly imbalance for said Gas Cost Zone and shall accrue for each month of the review period.

- The interest rate shall be the same rate as determined by the Public Utility Commission of Texas for refunds on customer deposits and in effect during the last month of the audit period (June).

- The sum of the monthly imbalances, plus interest, for each Gas Cost Zone for the period under review shall be the Reconciliation Amount, the total amount to be refunded/surcharged in said Gas Cost Zone.

If the Reconciliation Review indicates a gas loss or gas gain of greater than 5% of that metered into the system, the following methodology shall apply:

- WTGU shall calculate the imbalance between its Purchase Gas Cost and Sales Amount on a monthly basis for said Gas Cost Zones Purchase Gas Cost amounts in excess of the 1.0526 ratio shall be disallowed by:

  1) Dividing total Purchase Volumes for the 12-month review period by the total Sales Volumes for the same period in said Gas Cost Zone.

  2) Subtracting that result from 1, which when expressed as a percentage, becomes said Gas Cost Zones "Actual P/S Ratio."

  3) Subtracting 5.26% from said Gas Cost Zones Actual P/S Ratio, results in a "Disallowance Factor" for the review period.

  4) Multiplying the Disallowance Factor by the Purchase Volumes for each month and by the Weighted Average Cost of Gas for each month, for said Gas Cost Zone will result in an amount to be disallowed each month.

  5) The Net Jurisdictional Cost of Gas shall be calculated by multiplying the Total Jurisdictional Sales Volume by the Actual P/S Ratio to arrive at the Calculated Purchased Volume. The Calculated Purchased Volume is then multiplied by the WACOG to arrive at the Jurisdictional Cost of Gas. The Net Jurisdictional Cost of Gas is calculated by subtracting the Disallowed Amount calculated above.

- Interest shall be applied to each monthly imbalance for said Gas Cost Zone and shall accrue for each month of the review period.

- The interest rate shall be the rate in effect during the last month of the audit period (June).

- The sum of the monthly imbalances, plus interest, for the period under review shall be the Reconciliation Amount for said Gas Cost Zone or the total amount to be refunded/surcharged.

Reconciliation Factor Calculation (RFC)

The Reconciliation Amount for each Gas Cost Zone shall be divided by 12, resulting in the Reconciliation Component.

The Reconciliation Component shall be reflected in a refund or surcharge on each customer bill, according to Gas Cost Zone, over a twelve-month period beginning with the first billing cycle in September following the period covered by the review.

The Reconciliation Component for each month of the reconciliation period shall be calculated by dividing the Reconciliation Amount by the estimated Sales Volumes for the applicable billing period. The result will be a monthly Reconciliation Factor, expressed in Mcf for each Gas Cost Zone. Any under or over collection from the prior month may be factored in subsequent months' Reconciliation Component.

Each month during the reconciliation period, the PGF for each Gas Cost Zone on customer bills shall be increased or reduced by the product of the number of Mcf billed to the customer and the monthly Reconciliation Factor, as indicated in the section of PGF calculations. Any under or over collections remaining at the end of the gas reconciliation period will be carried forward to the next gas reconciliation period.

MISCELLANEOUS FEES AND DEPOSITS – ENVIRONS

APPLICABILITY

Applicable to Residential, Commercial, Industrial, and any other jurisdictional customers of West Texas Gas Utility, LLC ("WTGU") who are in an unincorporated or environs area served by WTGU.

FEES

Initiation of Service:

a) Connection Charge

The following connection charges apply:

Schedule	Charge
Business Hours (8AM to 5PM, Monday – Friday, except holidays)	$50.00
After Hours (All Hours not associated with Business Hours)	$70.00

A connect fee will 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.

b) Read-In for Change Charge

A read-in fee of $20.00 will 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.

c) After Hours & Special Handling

In addition to initiation of service fee above, a fee shall be charged to any applicant whose request to initiate service cannot be completed during normal business hours or requires special handling. Applicant shall be advised that an additional fee will be charged and must agree to pay such charge. Any fees assessed will reflect actual time incurred at $20 per hour during business hours and $30 per hour for after hours, plus the actual cost of materials and any incidental (third party) expenses. A third party is any person or entity, including an affiliate of the Company.

(i) **Special Handling:** West Texas Gas Utility, LLC ("WTGU") may, at customer's request, provide special handling in order to meet the Customer's requirements for a fee based on the rates indicated in (c) above. Special handling may include such assistance as calling the customer in advance or making other special arrangements (such as A.M. or P.M. scheduling) for access to the customer's premises.

(ii) **Expedited Service:** If the customer requires that the order be worked after hours for their convenience or if the customer requires expedited service, the charge shall be based on the rates indicated in (c) above for after-hours service work on customer premises. The Customer's request for expedited service may then be scheduled at any time to fit WTGU's work schedule but the after-hours charge shall be collected as long as any other work is done on overtime.

(iii) **Special Call Out:** If the initiation of service order requires special call out, the customer shall be charged based on the rates indicated in (c) above for after-hours service work on customer's premises.

Customer Requested Meter Test

Whenever WTGU is requested by a customer to have a meter test performed, and the result of that meter test indicates that the meter is within 2% accuracy and the meter has been tested within a four year period from the time the customer made the request the customer will be charged according to the following fee schedule.

Positive Displacement	Charge
275 cubic feet per hour or less	$25.00
276 to 1500 cubic feet per hour	$30.00
1501 to 3000 cubic feet per hour	$35.00
3001 to 5000 cubic feet per hour	$45.00
over 5000 cubic feet per hour	$60.00
Orifice Meters	
All sizes	$40.00

The meter test fees schedule above will not apply when the test results indicate the meter is outside of the allowed 2% accuracy range.

Returned Check/Bank Draft Charges

Accounts for which payment is made using checks or electronic drafts which are returned or denied by a bank for any reason may be charged a fee for each occurrence of $25.00.

Collection Fee

A fee of $20.00 will be charged to any customer whose failure to respond to a termination notice necessitates the dispatch of a Company representative who attempts collection of payment from customer.

Reconnect Fees

The following reconnection fees will be charged to any customer whose service is terminated and then re-initiated unless terminated in error by WTGU.

Schedule	Charge
Business Hours (8AM to 5PM, Monday – Friday, except holidays)	$50.00
After Hours (All Hours not associated with Business Hours)	$70.00

Temporary Service

Customers will be charged the actual cost of installation and removal of pipe and metering facilities. The actual cost will be calculated in accordance with the rates specified in Section 4.1.1 (c) above. This service does not include extension of mains.

Special Read

Customer requested reading of a meter for any purpose other than initiation of service will be charged $20.00

No Access

A fee of $20.00 will be charged to customer who schedules an appointment but fails to appear or Company personnel cannot access property to perform the service requested.

Tampering

Customers who tamper with their meters will be assessed a charge of $150.00 plus the actual cost of any estimated volumes of gas illegally consumed or improperly measured based on such tampering, and the actual cost of time and materials to repair meters or other company equipment. The actual costs will be based on the labor rates and costs specified in Section 4.1.1 (c) above. This charge is not intended to duplicate any charge that may be imposed by the Texas Penal Code.

Extension Fee

In the event the cost of extending mains in an incorporated area exceeds the free limit established by the Franchise Agreement for domestic and non-domestic customers in the area, customers shall pay the actual cost of the extension, based on costs calculated in accordance with the rates specified in Section 4.1.1 (c) above, less the free limit. In the event the Franchise Agreement does not establish a free limit, and in all unincorporated areas, the customers shall pay the actual cost of the extension, less a $150.00 credit, based on costs calculated in accordance with the rates specified in Section 4.1.1 (c) above.

DEPOSITS

Customer Deposits

Deposits will be based on 1/6 of the customers estimated annual usage. For any customer who pays bills by electronic transfer to WTGU, these deposits will be based on 1/12 of the customers estimated annual usage.

NON-PROFIT ENVIRONS SERVICE RATE

APPLICABILITY

Applicable to all non-profit customers.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Non-Profit consumers.

Customer Charge	$79.00
All Consumption @	$4.89 per Mcf

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

OTHER FEES

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 Gas Cost Adjustment-ENV.

Rate Case Expense Rider: 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.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-ENV.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provisions of Rate Schedule MISCFEES-ENV.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-ENV.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

WEST TEXAS GAS UTILITY, LLC **RATE SCHEDULE**
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OTHER SURCHARGES – ENVIRONS

West Texas Gas Utility, LLC will recover other surcharges from jurisdictional customers as authorized by federal, state and local regulatory authorities in accordance with applicable statutes, laws, regulations, orders, rules, contracts or agreements.

Effective: __________

PIPELINE SAFETY AND REGULATORY PROGRAM RATE SCHEDULE

Pipeline Safety and Regulatory Program Rate Schedule.

Applicability

Fee. Once annually, West Texas Gas Utility, LLC ("WTGU") shall remit to the Commission the fee required in 16 TEX. ADMIN. CODE Section 8.201.

Surcharge. During the next billing cycle following WTGU remittance to the Commission of the fee, WTGU shall include on its customers' bills a Pipeline Safety and Regulatory Program Surcharge, to the extent authorized in 16 TEX. ADMIN. CODE Section 8.201.

Formula. The Rule 8.201 surcharge is calculated in accordance with the following formula:

Rule 8.201(b) fee assessed by the Commission on WTGU
Divided by
Number of meters billed
Equals
Rule 8.201(b)(3) surcharge, applied per customer meter, once annually.

In this formula, the number of meters billed refers to the number of meters billed during the billing month that precedes the month the Rule 8.201(b)(3) surcharge is included on customer bills.

Compliance Report.
The Company shall file an annual pipeline safety fee (PSF) report no later than 90 days after the last billing cycle in which the pipeline safety and regulatory program fee surcharge is billed to customers. The Company shall file the report with the Railroad Commission of Texas addressed to the Director of Oversight and Safety Division, Gas Services Department, referencing Case No. OS-24-00017816, and titling the report "Pipeline Safety Fee Recovery Report". The report shall include the following:

a) the pipeline safety 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 the surcharge was billed to customers; and
d) the total amount collected from customers from the surcharge.

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

WEST TEXAS GAS UTILITY, LLC **RATE SCHEDULE**
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Effective: ____________

PUBLIC AUTHORITY SERVICE RATE - ENVIRONS

APPLICABILITY

Applicable to all public authority customers.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Public Authority consumers.

Customer Charge	$79.00
All Consumption @	$4.89 per Mcf

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

OTHER FEES

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 Gas Cost Adjustment-ENV.

Rate Case Expense Rider: 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.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-ENV.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provisions of Rate Schedule MISCFEES-ENV.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-ENV.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

ENVIRONS
QUALITY OF SERVICE RULES
RATE SCHEDULE

RULE §7.45 Quality of Service

For gas utility service to residential and small commercial customers, the following minimum service standards shall be applicable in unincorporated areas. In addition, each gas distribution utility is ordered to amend its service rules to include said minimum service standards within the utility service rules applicable to residential and small commercial customers within incorporated areas, but only to the extent that said minimum service standards do not conflict with standards lawfully established within a particular municipality for a gas distribution utility. Said gas distribution utility shall file service rules incorporating said minimum service standards with the Railroad Commission and with the municipalities in the manner prescribed by law.

(1) Continuity of service.

(A) Service interruptions.

(i) Every gas utility shall make all reasonable efforts to prevent interruptions of service. When interruptions occur, the utility shall reestablish service within the shortest possible time consistent with prudent operating principles so that the smallest number of customers are affected.

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

(iii) In the event of national emergency or local disaster resulting in disruption of normal service, the utility 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, each utility 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.

(C) Report to commission. The commission shall be notified in writing within 48 hours of interruptions in service affecting the entire system or any major division thereof lasting more than four hours. The notice shall also state the 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.

(2) Customer relations.

(A) Information to customers. Each utility shall:

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

(ii) assist the customer or applicant in selecting the most economical rate schedule;

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

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

(v) upon request inform its customers as to the method of reading meters;

(vi) provide to new customers, at the time service is initiated or as an insert in the first billing, a pamphlet or information packet containing the following information. This information shall be provided in English and Spanish as necessary to adequately inform the customers; provided, however, the regulatory authority upon application and a showing of good cause may exempt the utility from the requirement that the information be provided in Spanish:

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

(II) the customer's right to have his or her meter checked without charge under paragraph (7) of this section, if applicable;

(III) the time allowed to pay outstanding bills;

(IV) grounds for termination of service;

(V) the steps the utility must take before terminating service;

(VI) how the customer can resolve billing disputes with the utility and how disputes and health emergencies may affect termination of service;

(VII) information on alternative payment plans offered by the utility;

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

(IX) the appropriate regulatory authority with whom to register a complaint and how to contact such authority;

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

(XI) the customer's right to be instructed by the utility how to read his or her meter;

(vii) at least once each calendar year, notify customers that information is available upon request, at no charge to the customer, concerning the items listed in clause (vi)(I) - (XI) of this subparagraph. This notice may be accomplished by use of a billing insert or a printed statement upon the bill itself.

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

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

(D) Deferred payment plan. The utility is encouraged to offer a deferred payment plan for delinquent residential accounts. If such a plan is offered, it shall conform to the following guidelines:

(i) 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.

(ii) For purposes of determining reasonableness under these rules, the following shall be considered: size of delinquent account; customer's ability to pay; customer's payment history; time that the debt has been outstanding; reasons why debt has been outstanding; and other relevant factors concerning the circumstances of the customer.

(iii) A deferred payment plan, if reduced to writing, offered by a utility 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 utility's failure or refusal to comply with the terms of this agreement."

(iv) A deferred payment plan may include a one-time 5.0% penalty for late payment on 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 utility's error (such as an inaccurately estimated bill or an incorrectly read meter). A deferred payment plan shall not include a finance charge.

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

(vi) Any utility which institutes a deferred payment plan shall not refuse a customer participation in such a program on the basis of race, color, creed, sex, marital status, age, or any other form of discrimination prohibited by law.

(E) Delayed payment of bills by elderly persons.

(i) Applicability. This subparagraph applies only to:

(I) a utility that assesses late payment charges on residential customers and that suspends service before the 26th day after the date of the bill for which collection action is taken;

(II) utility bills issued on or after August 30, 1993; and

(III) an elderly person, as defined in clause (ii) of this subparagraph, who is a residential customer and who occupies the entire premises for which a delay is requested.

(ii) Definitions.

(I) Elderly person--A person who is 60 years of age or older.

(II) Utility--A gas utility or municipally owned utility, as defined in Texas Utilities Code, §§101.003(7), 101.003(8), and 121.001 - 121.006.

(iii) An elderly person may request that the utility implement the delay for either the most recent utility bill or for the most recent utility bill and each subsequent utility bill.

(iv) On request of an elderly person, a utility shall delay without penalty the payment date of a bill for providing utility services to that person until the 25th day after the date on which the bill is issued.

(v) The utility may require the requesting person to present reasonable proof that the person is 60 years of age or older.

(vi) Every utility shall notify its customers of this delayed payment option no less often than yearly. A utility may include this notice with other information provided pursuant to subparagraph (A) of this paragraph.

(3) Refusal of service.

(A) Compliance by applicant. Any utility may decline to serve an applicant for whom service is available from previously installed facilities until such applicant has complied with the state and municipal regulations and approved rules and regulations of the utility on file with the commission governing the service applied for or for the following reasons.

(i) Applicant's facilities inadequate. If the applicant's installation or equipment is known to be hazardous or of such character that satisfactory service cannot be given.

(ii) For indebtedness. If the applicant is indebted to any utility for the same kind of service as that applied for; provided, however, that in the event the indebtedness of the applicant for service is in dispute, the applicant shall be served upon complying with the applicable deposit requirement.

(iii) Refusal to make deposit. For refusal to make a deposit if applicant is required to make a deposit under these rules.

(B) Applicant's recourse. In the event that the utility shall refuse to serve an applicant under the provisions of these rules, the utility must inform the applicant of the basis of its refusal and that the applicant may file a complaint with the municipal regulatory authority or commission, whichever is appropriate.

(C) Insufficient grounds for refusal to serve. The following shall not constitute sufficient cause for refusal of service to a present customer or applicant:

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

(ii) failure to pay for merchandise or charges for nonutility service purchased from the utility;

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

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

(v) failure to pay a bill of another customer as guarantor thereof unless the guarantee was made in writing to the utility as a condition precedent to service; and

(vi) failure to pay the bill of another customer at the same address except where the change of customer identity is made to avoid or evade payment of a utility bill.

(4) Discontinuance of service.

(A) The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

(B) A utility may offer an inducement for prompt payment of bills by allowing a discount in the amount of 5.0% for payment of bills within 10 days after their issuance. This provision shall not apply where it conflicts with existing orders or ordinances of the appropriate regulatory authority.

(C) A customer's utility service may be disconnected if the bill has not been paid or a deferred payment plan pursuant to paragraph (2)(D) of this section has not been entered into within five working days after the bill has become delinquent and proper notice has been given. Proper notice consists of a deposit in the United States mail, postage prepaid, or hand delivery to the customer at least five working days prior to the stated date of disconnection, with the words "Termination Notice" or similar language prominently displayed on the notice. The notice shall be provided in English and Spanish as necessary to adequately inform the customer, and shall include the date of termination, the hours, address, and telephone number where payment may be made, and a statement that if a health or other emergency exists, the utility may be contacted concerning the nature of the emergency and the relief available, if any, to meet such emergency.

(D) Utility service may be disconnected for any of the following reasons:

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

(ii) violation of the utility's rules pertaining to the use of service in a manner which interferes with the service of others or the operation of nonstandard equipment, if a reasonable attempt has been made to notify the customer and the customer is provided with a reasonable opportunity to remedy the situation;

(iii) failure to comply with deposit or guarantee arrangements where required by paragraph (5) of this section;

(iv) without notice where a known dangerous condition exists for as long as the condition exists;

(v) tampering with the utility company's meter or equipment or bypassing the same.

(E) Utility service may not be disconnected for any of the following reasons:

(i) delinquency in payment for service by a previous occupant of the premises;

(ii) failure to pay for merchandise or charges for nonutility service by the utility;

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

(iv) failure to pay the account of another customer as guarantor thereof, unless the utility has in writing the guarantee as a condition precedent to service;

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

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

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

(F) Unless a dangerous condition exists, or unless the customer requests disconnection, service shall not be disconnected on a day, or on a day immediately preceding a day, when personnel of the utility are not available to the public for the purpose of making collections and reconnecting service.

(G) No utility may abandon a customer without written approval from the regulatory authority.

(H) No utility may discontinue service to a delinquent residential customer permanently residing in an individually metered dwelling unit when that customer establishes that discontinuance of service will result in some person residing at that residence becoming seriously ill or more seriously ill if the service is discontinued. Any customer seeking to avoid termination of service under this section must make a written request supported by a written statement from a licensed physician. Both the request and the statement must be received by the utility not more than five working days after the date of delinquency of the bill. The prohibition against service termination provided by this section shall last 20 days from the date of receipt by the utility of the request and statement or such lesser period as may be agreed upon by the utility and the customer. The customer who makes such request shall sign an installment agreement which provides for payment of such service along with timely payments for subsequent monthly billings.

(5) Applicant deposit.

(A) Establishment of credit for residential applicants. Each utility may require a residential applicant for service to satisfactorily establish credit but such establishment of credit shall not relieve the customer from complying with rules for prompt payment of bills. Subject to these rules, a residential applicant shall not be required to pay a deposit:

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

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

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

(B) Reestablishment of credit. Every applicant who has previously been a customer of the utility and whose service has been discontinued for nonpayment of bills shall be required before service is rendered to pay all his amounts due the utility or execute a written deferred payment agreement, if offered, and reestablish credit as provided in subparagraph (A) of this paragraph.

(C) Amount of deposit and interest for residential service, and exemption from deposit.

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

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

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

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

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

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

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

(E) Records of deposits.

(i) The utility shall keep records to show:

(I) the name and address of each depositor;

(II) the amount and date of the deposit; and

(III) each transaction concerning the deposit.

(ii) The utility shall issue a receipt of deposit to each applicant from whom a deposit is received and shall provide means whereby a depositor may establish claim if the receipt is lost.

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

(F) Refund of deposit.

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

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

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

(H) Complaint by applicant or customer. Each utility shall direct its personnel engaged in initial contact with an applicant or customer for service seeking to establish or reestablish credit under the provisions of these rules to inform the customer, if dissatisfaction is expressed with the utility's decision, of the customer's right to file a complaint with the regulatory authority thereon.

(6) Billing.

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

(B) The customer's bill must show all the following information. The information must be arranged and displayed in such a manner as to allow the customer to compute his bill with the applicable rate schedule. The applicable rate schedule must be mailed to the customer on request of the customer. A utility may exhaust its present stock of nonconforming bill forms before compliance is required by this section:

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

(ii) the number and kind of units billed;

(iii) the applicable rate schedule title or code;

(iv) the total base bill;

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

(vi) the date by which the customer must pay the bill to get prompt payment discount;

(vii) the total amount due before and after any discount for prompt payment within a designated period;

(viii) a distinct marking to identify an estimated bill.

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

(D) Disputed bills.

(i) In the event of a dispute between the customer and the utility regarding the bill, the utility must forthwith make such investigation as is required by the particular case and report the results thereof to the customer. If the customer wishes to obtain the benefits of clause (ii) of this subparagraph, notification of the dispute must be given to the utility prior to the date the bill becomes delinquent. In the event the dispute is not resolved, the utility shall inform the customer of the complaint procedures of the appropriate regulatory authority.

(ii) 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.

(7) Meters.

(A) Meter requirements.

(i) Use of meter. All gas sold by a utility must be charged for by meter measurements, except where otherwise provided for by applicable law, regulation of the regulatory authority, or tariff.

(ii) Installation by utility. Unless otherwise authorized by the regulatory authority, each utility must provide and install and will continue to own and maintain all meters necessary for measurement of gas delivered to its customers.

(iii) Standard type. No utility may furnish, set up, or put in use any meter which is not reliable and of a standard type which meets generally accepted industry standards; provided, however, special meters not necessarily conforming to such standard types may be used for investigation, testing, or experimental purposes.

(B) Meter records. Each utility must keep the following records:

(i) Meter equipment records. Each utility must keep a record of all its meters, showing the customer's address and date of the last test.

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

(iii) Meter readings--meter unit location. In general, each meter must indicate clearly the units of service for which charge is made to the customer.

(iv) Meter tests on request of customer.

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

(II) Notwithstanding subclause (I) of this clause, if the meter is found to be more than nominally defective, to either the customer's or the utility's disadvantage, any fee charged for a meter test must be refunded to the customer. More than nominally defective means a deviation of more than 2.0% from accurate registration.

(v) Bill adjustments due to meter error.

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

(-a-) the last six months; or

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

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

(8) New construction.

(A) Standards of construction. Each utility is to construct, install, operate, and maintain its plant, structures, equipment, and lines in accordance with the provisions of such codes and standards as are generally accepted by the industry, as modified by rule or regulation of the regulatory authority or otherwise by law, and in such manner to best accommodate the public and to prevent interference with service furnished by other public utilities insofar as practical.

(B) Line extension and construction charges. Every utility must file its extension policy. The policy must be consistent, nondiscriminatory, and is subject to the approval of the regulatory authority. No contribution in aid of construction may be required of any customer except as provided for in extension policy.

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

RATE CASE EXPENSE SURCHARGE – ENVIRONS

APPLICABILITY

All jurisdictional customers in the unincorporated or environs areas of West Texas Gas Utility, LLC ("WTGU") Service Area.

RCE RATE

Pursuant to the Final Order in Case No. OS-24-00017816, WTGU is authorized to recover a total not to exceed $___ in rate case expenses from Case No. OS-24-00017816 jurisdictional customers by a surcharge applicable to all jurisdictional customers in incorporated and unincorporated areas at the rate of $0.___/Mcf for a period of approximately ___ months commencing _________.

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 Case No. OS-024-00017816, 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

WEST TEXAS GAS UTILITY, LLC **RATE SCHEDULE**
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Effective: ____________

RESIDENTIAL SERVICE RATE – ENVIRONS

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 in an unincorporated or environs area served by West Texas Gas Utility, LLC ("WTGU"). A residential consumer includes an individually-metered residential unit or dwelling and builders prior to sale or re-sale of a property for domestic purposes. This rate is only available to full requirements customers of WTGU.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Residential consumers per meter billing cycle or for any part of a billing cycle for which gas service is available at the same location.

Customer Charge	$29.50
All Consumption @	$7.68 per Mcf

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

OTHER FEES

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 Gas Cost Adjustment-ENV.

Rate Case Expense Rider: 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.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-ENV.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provisions of Rate Schedule MISCFEES-ENV.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-ENV.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

Effective: ____________

TAX ADJUSTMENT – ENVIRONS

REVENUE RELATED TAX ADJUSTMENT

Each monthly bill for a jurisdictional customer, as adjusted, shall also be adjusted by an amount equivalent to the various revenue related taxes, franchise fees, rentals, or other fees and charges imposed by regulatory or governmental authorities. This includes, but not limited to, Gross Receipts Taxes or any other governmental imposition, rental fee or charge levied that is based on any portion of revenues billed by West Texas Gas Utility, LLC.

WINTER STORM URI SURCHARGE

APPLICABILITY

All jurisdictional customers in the unincorporated or environs areas of West Texas Gas Utility, LLC ("WTGU") Service Area.

PURPOSE

The purpose of the Winter Storm Uri Surcharge is to authorize WTGU to recover the reasonable, necessary, and prudent extraordinary gas costs incurred by WTGU as a result of Winter Storm Uri. The rate schedule is authorized by the Railroad Commission of Texas's ("Commission") Final Order in Case No. OS-24-00017816, which approved a Winter Storm Uri Regulatory Asset and the recovery of the costs contained in the regulatory asset through a monthly surcharge. WTGU is authorized and directed to assess the Winter Storm Uri Surcharge rate as set forth in the section below.

SURCHARGE RATE

All Mcf during each billing period: $0.41 per Mcf.

This rate will be in effect until all approved and expended Winter Storm Uri costs, up to $3,502,862.41 ("Regulatory Asset Amount"), are recovered under the applicable rate schedules. Any excess recovery of the Regulatory Asset Amount shall be calculated and refunded to customers through a final true-up under this rate schedule.

OTHER ADJUSTMENTS

<u>Taxes</u>: Plus applicable taxes and fees (including franchise fees) related to above.

CONDITIONS

1. Subject to all applicable laws and orders, and WTGU's rules and regulations on file with the regulatory authority.
2. Uncollectible amounts, actually written off, associated with this surcharge shall be added back to the balance to be recovered via this surcharge.
3. Any amounts that were included in the Regulatory Asset Amount that are refunded to WTGU subsequent to the Final Order in Case No. OS-24-00017816 shall be subtracted from the balance and shall not be recovered via this surcharge.

WINTER STORM URI SURCHARGE RECOVERY COMPLIANCE REPORT

WTGU shall file a reconciliation report annually on or before March 31, commencing in 2026 and ceasing after a reconciliation report is filed at the end of the month following the month in which the Regulatory Asset Amount is fully recovered via the final reconciliation true-up (if applicable). WTGU shall file the report with the Commission, addressed to the Director of the Oversight and Safety Division and referencing Case No. OS-24-00017816, Winter Storm Uri Surcharge Recovery Report. The report shall include:

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

Reports for the Commission should be filed electronically at GUD_Compliance@rrc.texas.gov or at the following address:

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

WEST TEXAS GAS UTILITY, LLC **RATE SCHEDULE**
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COMMERCIAL SERVICE RATE - INCORPORATED

APPLICABILITY

Applicable to all commercial customers and to customers not otherwise specifically provided for under any other rate schedule or served under a contract in an incorporated area or city served by West Texas Gas Utility, LLC ("WTGU"). This rate is only available to full requirements customers of WTGU.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Commercial consumers and to consumers not otherwise specifically provided for under any other rate schedule or served under a contract per meter billing cycle or for any part of a billing cycle for which gas service is available at the same location.

Customer Charge	$79.00
All Consumption @	$4.89 per Mcf

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

OTHER FEES

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 Gas Cost Adjustment- INC.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE- INC.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee- INC.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provision of Rate Schedule MISCFEES- INC.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-INC.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

Effective: ____________

GAS COST ADJUSTMENT – INCORPORATED

Applicability

This clause shall apply to all customers served by WTGU, except for customers purchasing gas at contract rates. Each customer's gas costs will be determined by the costs incurred in the applicable Gas Cost Zone. For purposes of determining gas purchase costs, all customers will be located in one of three Gas Cost Zones: North, South, and West. Each Gas Cost Zone consists of the following systems or geographic areas:

NORTH GAS COST ZONE:
Incorporated areas of the Cities of Amarillo, Cactus, Canadian, Canyon, Claude, Dalhart, Darrouzett, Farwell, Follett, Groom, Higgins, Miami, Mobeetie, Shamrock, Stratford, Texhoma, Texline, Wheeler and White Deer.

SOUTH GAS COST ZONE:
Incorporated areas of the Cities of Devine, Eden, Junction, La Vernia, Lockhart, Luling, Menard, Natalia, Paint Rock, Seguin, Somerset and Sonora.

WEST GAS COST ZONE:
Incorporated areas of the Cities of Balmorhea, Kermit, Lubbock, Van Horn, and Wolfforth.

Intent

This clause is intended to allow collection of West Texas Gas Utility, LLC ("WTGU") gas purchase costs in a manner that will lessen monthly fluctuations in the gas cost factor and ensure that all amounts billed to customers are fully reconciled with actual costs incurred, subject to limitations for excessive lost and unaccounted for gas.

Definitions

Gas Cost Zones – North, South, and West, as defined in the "Applicability" section below.

Interest – The percentage of interest shall be the interest rate established by the Public Utility Commission, or such other agency or manner as determined by the Commission, under Chapter 183 of the Texas Utilities Code.

Lost and Unaccounted For Gas – Lost and Unaccounted for Gas (LUG) shall represent volumes of gas metered into the distribution system and volumes of gas metered out of the distribution system at 14.65 p.s.i.a., which shall include distribution and non-distribution volumes. WTGU transmission LUG shall not be included in these volumes.

Purchased Gas Costs –The total cost of Purchase Volumes, as received into the Company's distribution systems within each Gas Cost Zone.

Purchased Gas Factor ("PGF") – A factor on each customer's monthly bill, expressed in dollars per Mcf, to reflect the Purchase Gas Costs, all as more specifically described herein.

Purchase/Sales Ratio – A ratio determined by dividing the Company's Purchase Volumes metered into the distribution system during the twelve-month period ending June 30 of each year by the sum of the Company's Sales Volumes metered out of the distribution system, volumes of metered Company used gas, and losses of gas from the Company's systems within each Gas Cost Zone that have been billed to third parties during the same period. Such ratio as determined shall in no event exceed 1.0526 i.e. 1/1(1-.05) unless expressly authorized by the applicable regulatory authority.

Purchase Volumes – The volumes of gas, expressed in Mcf's and stated at 14.65 psia, received by the Company's distribution system from all sources within each Gas Cost Zone, including monthly purchases and withdrawals from storage, if any, for use by general service customers. This quantity of gas shall not include LUG attributable to the WTGU Transmission System or transmission function.

Reconciliation Amount – The net of any monthly imbalances by Gas Cost Zone during the period covered by the Reconciliation Review.

Reconciliation Component – The monthly amount to be refunded or passed through to customers within each Gas Cost Zone, consisting of one-twelfth of the Reconciliation Amount.

Reconciliation Factor – A factor, expressed as a cost per Mcf on customer bills within each Gas Cost Zone, reflecting the customer's share of the Reconciliation Component applicable to the period covered by the bill.

Reconciliation Review – An annual review of the Company's records covering each 12-month period ending June 30 to determine any imbalances between the Purchase Gas Cost and the Sales Amount as applied to each Gas Cost Zone during that period.

Sales Amount – Sales Volumes, volumes of metered Company used gas, and losses of gas from the Company's system within each Gas Cost Zone that have been billed to third parties, multiplied by the Purchased Gas Factor.

Sales Volumes – The volumes of gas metered to general service customers within each Gas Cost Zone expressed in Mcf's and stated at 14.65 psia.

Weighted Average Cost of Gas – The Purchase Gas Costs invoiced by third parties divided by the Purchase Volumes, calculated on a monthly basis for each Gas Cost Zone

Purchase Gas Cost Component (PGC)

The Purchase Gas Cost for each Gas Cost Zone shall be computed utilizing the following components for the distribution system customers:

- Cost of gas purchased
- Credits, Refunds or Out of Period adjustments
- Cost of gas withdrawn from storage
- Interest on storage gas withdrawn
- Upstream Gathering and Transportation Charges
- Storage Deliverability Charges
- Storage Capacity Charges
- New taxes on the purchased gas or the purchase transaction and not reflected on elsewhere on customer bills

WTGU shall keep accurate records of all storage gas purchases, including the date, quantity, cost, and associated expenses. WTGU shall account for storage gas purchases and withdrawals using a weighted average cost basis.

Purchased Gas Factor (PGF) Calculation

Each customer bill shall include a Purchased Gas Factor reflecting the estimated Weighted Average Cost of Gas, plus additional elements described in this section, during the period covered by the bill for each Gas Cost Zone. The PGF shall be determined to the nearest $0.001 per Mcf, and the following provisions shall apply:

- In addition to the estimated weighted average cost of gas for the current month's billing period, the PGF may include a pro rata portion of an amount reflecting the difference between the estimated Weighted Average Cost of Gas and the actual Weighted Average Cost of Gas during the previous billing period for each Gas Cost Zone
- The PGF shall also include a "Reconciliation Factor," an amount reflecting the customer's share of any gas cost imbalances in the preceding reconciliation period for each Gas Cost Zone.
- The PGF factor may also include an amount reflecting any new taxes or levies specifically applied to gas costs or purchases and not otherwise reflected on the customer bill for each Gas Cost Zone.

The Purchased Gas Factor is expressed as a formula as follows:

$$(A+/-B) + C + D = E$$

Where:

A = Estimated WACOG
B = Est. WACOG/Act. WACOG Difference
C = Reconciliation Factor
D = New Taxes
E = Total PGF

Gas Cost Reconciliation (GCR)

WTGU shall keep accurate books and records of the Reconciliation Review, monthly Purchased Gas Factor reports to the Railroad Commission of Texas, and shall account for the Reconciliation Component and the Reconciliation Factors for each Gas Cost Zone.

A Reconciliation Review and calculation shall first determine whether the lost and unaccounted for gas is more or less than 5% of that metered into the system. The sales volumes shall be converted to the same pressure base as the purchase volumes. Calculations of the sales volumes furnished to its gas sales customers (from meters not corrected for pressure and/or temperature) shall be calculated utilizing the following service pressures (psia):

Incorporated areas of the Cities of:

Amarillo	13.38	Higgins	13.78	Shamrock	13.88
Balmorhea	13.48	Junction	14.18	Somerset	14.68
Cactus	13.28	Kermit	13.68	Sonora	13.98
Canadian	13.88	La Vernia	14.68	Stratford	13.18
Canyon	13.45	Lockhart	14.68	Texhoma	13.38
Claude	13.38	Lubbock	13.45	Texline	12.98
Dalhart	13.07	Luling	14.68	Van Horn	13.48
Darrouzett	13.78	Menard	14.08	Wheeler	13.78
Devine	14.68	Miami	13.68	White Deer	13.38
Eden	14.08	Mobeetie	13.78	Wolfforth	13.45
Farwell	13.18	Natalia	14.68		
Follett	13.68	Paint Rock	14.28		
Groom	13.38	Seguin	14.68		

If the Reconciliation Review indicates a gas loss or gas gain of less than 5% of that metered into the system, the following methodology shall apply:

- WTGU shall calculate the imbalance between its Net Jurisdictional Cost of Gas and amount collected through the PGA billed on a monthly basis for said Gas Cost Zone. The Net Jurisdictional Cost of Gas shall be calculated by multiplying the Total Jurisdictional Sales Volumes by the Actual P/S Ratio to arrive at the Calculated Purchased Volume. The Calculated Purchased Volume is then multiplied by the WACOG to arrive at the Net Jurisdictional Cost of Gas.

- Interest shall be applied to each monthly imbalance for said Gas Cost Zone and shall accrue for each month of the review period.

- The interest rate shall be the same rate as determined by the Public Utility Commission of Texas for refunds on customer deposits and in effect during the last month of the audit period (June).

- The sum of the monthly imbalances, plus interest, for each Gas Cost Zone for the period under review shall be the Reconciliation Amount, the total amount to be refunded/surcharged in said Gas Cost Zone.

If the Reconciliation Review indicates a gas loss or gas gain of greater than 5% of that metered into the system, the following methodology shall apply:

- WTGU shall calculate the imbalance between its Purchase Gas Cost and Sales Amount on a monthly basis for said Gas Cost Zones Purchase Gas Cost amounts in excess of the 1.0526 ratio shall be disallowed by:

  1) Dividing total Purchase Volumes for the 12-month review period by the total Sales Volumes for the same period in said Gas Cost Zone.

  2) Subtracting that result from 1, which when expressed as a percentage, becomes said Gas Cost Zones "Actual P/S Ratio."

  3) Subtracting 5.26% from said Gas Cost Zones Actual P/S Ratio, results in a "Disallowance Factor" for the review period.

  4) Multiplying the Disallowance Factor by the Purchase Volumes for each month and by the Weighted Average Cost of Gas for each month, for said Gas Cost Zone will result in an amount to be disallowed each month.

  5) The Net Jurisdictional Cost of Gas shall be calculated by multiplying the Total Jurisdictional Sales Volume by the Actual P/S Ratio to arrive at the Calculated Purchased Volume. The Calculated Purchased Volume is then multiplied by the WACOG to arrive at the Jurisdictional Cost of Gas. The Net Jurisdictional Cost of Gas is calculated by subtracting the Disallowed Amount calculated above.

- Interest shall be applied to each monthly imbalance for said Gas Cost Zone and shall accrue for each month of the review period.

- The interest rate shall be the rate in effect during the last month of the audit period (June).

- The sum of the monthly imbalances, plus interest, for the period under review shall be the Reconciliation Amount for said Gas Cost Zone or the total amount to be refunded/surcharged.

Reconciliation Factor Calculation (RFC)

The Reconciliation Amount for each Gas Cost Zone shall be divided by 12, resulting in the Reconciliation Component.

The Reconciliation Component shall be reflected in a refund or surcharge on each customer bill, according to Gas Cost Zone, over a twelve-month period beginning with the first billing cycle in September following the period covered by the review.

The Reconciliation Component for each month of the reconciliation period shall be calculated by dividing the Reconciliation Amount by the estimated Sales Volumes for the applicable billing period. The result will be a monthly Reconciliation Factor, expressed in Mcf for each Gas Cost Zone. Any under or over collection from the prior month may be factored in subsequent months' Reconciliation Component.

Each month during the reconciliation period, the PGF for each Gas Cost Zone on customer bills shall be increased or reduced by the product of the number of Mcf billed to the customer and the monthly Reconciliation Factor, as indicated in the section of PGF calculations. Any under or over collections remaining at the end of the gas reconciliation period will be carried forward to the next gas reconciliation period.

MISCELLANEOUS FEES AND DEPOSITS – INCORPORATED

APPLICABILITY

Applicable to Residential, Commercial, Industrial, and any other jurisdictional customers of West Texas Gas Utility, LLC ("WTGU") who are in an incorporated area or city served by WTGU.

FEES

Initiation of Service:

a) Connection Charge

The following connection charges apply:

Schedule	Charge
Business Hours (8AM to 5PM, Monday – Friday, except holidays)	$50.00
After Hours (All Hours not associated with Business Hours)	$70.00

A connect fee will 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.

b) Read-In for Change Charge

A read-in fee of $20.00 will 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.

c) After Hours & Special Handling

In addition to initiation of service fee above, a fee shall be charged to any applicant whose request to initiate service cannot be completed during normal business hours or requires special handling. Applicant shall be advised that an additional fee will be charged and must agree to pay such charge. Any fees assessed will reflect actual time incurred at $20 per hour during business hours and $30 per hour for after hours, plus the actual cost of materials and any incidental (third party) expenses. A third party is any person or entity, including an affiliate of the Company.

(i) **Special Handling:** West Texas Gas Utility, LLC ("WTGU") may, at customer's request, provide special handling in order to meet the Customer's requirements for a fee based on the rates indicated in (c) above. Special handling may include such assistance as calling the customer in advance or making other special arrangements (such as A.M. or P.M. scheduling) for access to the customer's premises.

(ii) **Expedited Service:** If the customer requires that the order be worked after hours for their convenience or if the customer requires expedited service, the charge shall be based on the rates indicated in (c) above for after-hours service work on customer premises. The Customer's request for expedited service may then be scheduled at any time to fit WTGU's work schedule but the after-hours charge shall be collected as long as any other work is done on overtime.

(iii) **Special Call Out:** If the initiation of service order requires special call out, the customer shall be charged based on the rates indicated in (c) above for after-hours service work on customer's premises.

Customer Requested Meter Test

Whenever WTGU is requested by a customer to have a meter test performed, and the result of that meter test indicates that the meter is within 2% accuracy and the meter has been tested within a four year period from the time the customer made the request the customer will be charged according to the following fee schedule.

Positive Displacement	Charge
275 cubic feet per hour or less	$25.00
276 to 1500 cubic feet per hour	$30.00
1501 to 3000 cubic feet per hour	$35.00
3001 to 5000 cubic feet per hour	$45.00
over 5000 cubic feet per hour	$60.00
Orifice Meters	
All sizes	$40.00

The meter test fees schedule above will not apply when the test results indicate the meter is outside of the allowed 2% accuracy range.

Returned Check/Bank Draft Charges

Accounts for which payment is made using checks or electronic drafts which are returned or denied by a bank for any reason may be charged a fee for each occurrence of $25.00.

Collection Fee

A fee of $20.00 will be charged to any customer whose failure to respond to a termination notice necessitates the dispatch of a Company representative who attempts collection of payment from customer.

Reconnect Fees

The following reconnection fees will be charged to any customer whose service is terminated and then re-initiated unless terminated in error by WTGU.

Schedule	Charge
Business Hours (8AM to 5PM, Monday – Friday, except holidays)	$50.00
After Hours (All Hours not associated with Business Hours)	$70.00

Temporary Service

Customers will be charged the actual cost of installation and removal of pipe and metering facilities. The actual cost will be calculated in accordance with the rates specified in Section 4.1.1 (c) above. This service does not include extension of mains.

Special Read

Customer requested reading of a meter for any purpose other than initiation of service will be charged $20.00

No Access

A fee of $20.00 will be charged to customer who schedules an appointment but fails to appear or Company personnel cannot access property to perform the service requested.

Tampering

Customers who tamper with their meters will be assessed a charge of $150.00 plus the actual cost of any estimated volumes of gas illegally consumed or improperly measured based on such tampering, and the actual cost of time and materials to repair meters or other company equipment. The actual costs will be based on the labor rates and costs specified in Section 4.1.1 (c) above. This charge is not intended to duplicate any charge that may be imposed by the Texas Penal Code.

Extension Fee

In the event the cost of extending mains in an incorporated area exceeds the free limit established by the Franchise Agreement for domestic and non-domestic customers in the area, customers shall pay the actual cost of the extension, based on costs calculated in accordance with the rates specified in Section 4.1.1 (c) above, less the free limit. In the event the Franchise Agreement does not establish a free limit, and in all unincorporated areas, the customers shall pay the actual cost of the extension, less a $150.00 credit, based on costs calculated in accordance with the rates specified in Section 4.1.1 (c) above.

DEPOSITS

Customer Deposits

Deposits will be based on 1/6 of the customers estimated annual usage. For any customer who pays bills by electronic transfer to WTGU, these deposits will be based on 1/12 of the customers estimated annual usage.

Effective: ____________

NON-PROFIT INCORPORATED
SERVICE RATE

APPLICABILITY

Applicable to all non-profit customers.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Non-Profit consumers.

Customer Charge	$79.00
All Consumption @	$4.89 per Mcf

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

OTHER FEES

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 Gas Cost Adjustment-INC.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-INC.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-INC.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provision of Rate Schedule MISCFEES-INC.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-INC.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

OTHER SURCHARGES – INCORPORATED

West Texas Gas Utility, LLC will recover other surcharges from jurisdictional customers as authorized by federal, state and local regulatory authorities in accordance with applicable statutes, laws, regulations, ordinances, orders, rules, contracts or agreements.

Effective: __________

PIPELINE SAFETY AND REGULATORY PROGRAM
RATE SCHEDULE

Pipeline Safety and Regulatory Program Rate Schedule.

Applicability

Fee. Once annually, West Texas Gas Utility, LLC ("WTGU") shall remit to the Commission the fee required in 16 TEX. ADMIN. CODE Section 8.201.

Surcharge. During the next billing cycle following WTGU remittance to the Commission of the fee, WTGU shall include on its customers' bills a Pipeline Safety and Regulatory Program Surcharge, to the extent authorized in 16 TEX. ADMIN. CODE Section 8.201.

Formula. The Rule 8.201 surcharge is calculated in accordance with the following formula:

Rule 8.201(b) fee assessed by the Commission on WTGU
Divided by
Number of meters billed
Equals
Rule 8.201(b)(3) surcharge, applied per customer meter, once annually.

In this formula, the number of meters billed refers to the number of meters billed during the billing month that precedes the month the Rule 8.201(b)(3) surcharge is included on customer bills.

Compliance Report.
The Company shall file an annual pipeline safety fee (PSF) report no later than 90 days after the last billing cycle in which the pipeline safety and regulatory program fee surcharge is billed to customers. The Company shall file the report with the Railroad Commission of Texas addressed to the Director of Oversight and Safety Division, Gas Services Department, referencing Case No. OS-24-00017816, and titling the report "Pipeline Safety Fee Recovery Report". The report shall include the following:

a) the pipeline safety 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 the surcharge was billed to customers; and
d) the total amount collected from customers from the surcharge.

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

WEST TEXAS GAS UTILITY, LLC **RATE SCHEDULE**
Page 1 of 1 **PA-INC**
Effective: ____________

PUBLIC AUTHORITY SERVICE RATE - INCORPORATED

APPLICABILITY

Applicable to all public authority customers.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Public Authority consumers.

Customer Charge	$79.00
All Consumption @	$4.89 per Mcf

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

OTHER FEES

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 Gas Cost Adjustment-INC.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-INC.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee-INC.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provision of Rate Schedule MISCFEE-INC.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS-INC.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

INCORPORATED
QUALITY OF SERVICE RULES
RATE SCHEDULE

RULE §7.45 Quality of Service

For gas utility service to residential and small commercial customers, the following minimum service standards shall be applicable in unincorporated areas. In addition, each gas distribution utility is ordered to amend its service rules to include said minimum service standards within the utility service rules applicable to residential and small commercial customers within incorporated areas, but only to the extent that said minimum service standards do not conflict with standards lawfully established within a particular municipality for a gas distribution utility. Said gas distribution utility shall file service rules incorporating said minimum service standards with the Railroad Commission and with the municipalities in the manner prescribed by law.

(1) Continuity of service.

(A) Service interruptions.

(i) Every gas utility shall make all reasonable efforts to prevent interruptions of service. When interruptions occur, the utility shall reestablish service within the shortest possible time consistent with prudent operating principles so that the smallest number of customers are affected.

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

(iii) In the event of national emergency or local disaster resulting in disruption of normal service, the utility 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, each utility 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.

(C) Report to commission. The commission shall be notified in writing within 48 hours of interruptions in service affecting the entire system or any major division thereof lasting more than four hours. The notice shall also state the 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.

(2) Customer relations.

(A) Information to customers. Each utility shall:

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

(ii) assist the customer or applicant in selecting the most economical rate schedule;

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

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

(v) upon request inform its customers as to the method of reading meters;

(vi) provide to new customers, at the time service is initiated or as an insert in the first billing, a pamphlet or information packet containing the following information. This information shall be provided in English and Spanish as necessary to adequately inform the customers; provided, however, the regulatory authority upon application and a showing of good cause may exempt the utility from the requirement that the information be provided in Spanish:

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

(II) the customer's right to have his or her meter checked without charge under paragraph (7) of this section, if applicable;

(III) the time allowed to pay outstanding bills;

(IV) grounds for termination of service;

(V) the steps the utility must take before terminating service;

(VI) how the customer can resolve billing disputes with the utility and how disputes and health emergencies may affect termination of service;

(VII) information on alternative payment plans offered by the utility;

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

(IX) the appropriate regulatory authority with whom to register a complaint and how to contact such authority;

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

(XI) the customer's right to be instructed by the utility how to read his or her meter;

(vii) at least once each calendar year, notify customers that information is available upon request, at no charge to the customer, concerning the items listed in clause (vi)(I) - (XI) of this subparagraph. This notice may be accomplished by use of a billing insert or a printed statement upon the bill itself.

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

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

(D) Deferred payment plan. The utility is encouraged to offer a deferred payment plan for delinquent residential accounts. If such a plan is offered, it shall conform to the following guidelines:

(i) 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.

(ii) For purposes of determining reasonableness under these rules, the following shall be considered: size of delinquent account; customer's ability to pay; customer's payment history; time that the debt has been outstanding; reasons why debt has been outstanding; and other relevant factors concerning the circumstances of the customer.

(iii) A deferred payment plan, if reduced to writing, offered by a utility 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 utility's failure or refusal to comply with the terms of this agreement."

(iv) A deferred payment plan may include a one-time 5.0% penalty for late payment on 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 utility's error (such as an inaccurately estimated bill or an incorrectly read meter). A deferred payment plan shall not include a finance charge.

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

(vi) Any utility which institutes a deferred payment plan shall not refuse a customer participation in such a program on the basis of race, color, creed, sex, marital status, age, or any other form of discrimination prohibited by law.

(E) Delayed payment of bills by elderly persons.

(i) Applicability. This subparagraph applies only to:

(I) a utility that assesses late payment charges on residential customers and that suspends service before the 26th day after the date of the bill for which collection action is taken;

(II) utility bills issued on or after August 30, 1993; and

(III) an elderly person, as defined in clause (ii) of this subparagraph, who is a residential customer and who occupies the entire premises for which a delay is requested.

(ii) Definitions.

(I) Elderly person--A person who is 60 years of age or older.

(II) Utility--A gas utility or municipally owned utility, as defined in Texas Utilities Code, §§101.003(7), 101.003(8), and 121.001 - 121.006.

(iii) An elderly person may request that the utility implement the delay for either the most recent utility bill or for the most recent utility bill and each subsequent utility bill.

(iv) On request of an elderly person, a utility shall delay without penalty the payment date of a bill for providing utility services to that person until the 25th day after the date on which the bill is issued.

(v) The utility may require the requesting person to present reasonable proof that the person is 60 years of age or older.

(vi) Every utility shall notify its customers of this delayed payment option no less often than yearly. A utility may include this notice with other information provided pursuant to subparagraph (A) of this paragraph.

(3) Refusal of service.

(A) Compliance by applicant. Any utility may decline to serve an applicant for whom service is available from previously installed facilities until such applicant has complied with the state and municipal regulations and approved rules and regulations of the utility on file with the commission governing the service applied for or for the following reasons.

(i) Applicant's facilities inadequate. If the applicant's installation or equipment is known to be hazardous or of such character that satisfactory service cannot be given.

(ii) For indebtedness. If the applicant is indebted to any utility for the same kind of service as that applied for; provided, however, that in the event the indebtedness of the applicant for service is in dispute, the applicant shall be served upon complying with the applicable deposit requirement.

(iii) Refusal to make deposit. For refusal to make a deposit if applicant is required to make a deposit under these rules.

(B) Applicant's recourse. In the event that the utility shall refuse to serve an applicant under the provisions of these rules, the utility must inform the applicant of the basis of its refusal and that the applicant may file a complaint with the municipal regulatory authority or commission, whichever is appropriate.

(C) Insufficient grounds for refusal to serve. The following shall not constitute sufficient cause for refusal of service to a present customer or applicant:

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

(ii) failure to pay for merchandise or charges for nonutility service purchased from the utility;

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

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

(v) failure to pay a bill of another customer as guarantor thereof unless the guarantee was made in writing to the utility as a condition precedent to service; and

(vi) failure to pay the bill of another customer at the same address except where the change of customer identity is made to avoid or evade payment of a utility bill.

(4) Discontinuance of service.

(A) The due date of the bill for utility service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the regulatory authority. A bill for utility service is delinquent if unpaid by the due date.

(B) A utility may offer an inducement for prompt payment of bills by allowing a discount in the amount of 5.0% for payment of bills within 10 days after their issuance. This provision shall not apply where it conflicts with existing orders or ordinances of the appropriate regulatory authority.

(C) A customer's utility service may be disconnected if the bill has not been paid or a deferred payment plan pursuant to paragraph (2)(D) of this section has not been entered into within five working days after the bill has become delinquent and proper notice has been given. Proper notice consists of a deposit in the United States mail, postage prepaid, or hand delivery to the customer at least five working days prior to the stated date of disconnection, with the words "Termination Notice" or similar language prominently displayed on the notice. The notice shall be provided in English and Spanish as necessary to adequately inform the customer, and shall include the date of termination, the hours, address, and telephone number where payment may be made, and a statement that if a health or other emergency exists, the utility may be contacted concerning the nature of the emergency and the relief available, if any, to meet such emergency.

(D) Utility service may be disconnected for any of the following reasons:

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

(ii) violation of the utility's rules pertaining to the use of service in a manner which interferes with the service of others or the operation of nonstandard equipment, if a reasonable attempt has been made to notify the customer and the customer is provided with a reasonable opportunity to remedy the situation;

(iii) failure to comply with deposit or guarantee arrangements where required by paragraph (5) of this section;

(iv) without notice where a known dangerous condition exists for as long as the condition exists;

(v) tampering with the utility company's meter or equipment or bypassing the same.

(E) Utility service may not be disconnected for any of the following reasons:

(i) delinquency in payment for service by a previous occupant of the premises;

(ii) failure to pay for merchandise or charges for nonutility service by the utility;

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

(iv) failure to pay the account of another customer as guarantor thereof, unless the utility has in writing the guarantee as a condition precedent to service;

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

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

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

(F) Unless a dangerous condition exists, or unless the customer requests disconnection, service shall not be disconnected on a day, or on a day immediately preceding a day, when personnel of the utility are not available to the public for the purpose of making collections and reconnecting service.

(G) No utility may abandon a customer without written approval from the regulatory authority.

(H) No utility may discontinue service to a delinquent residential customer permanently residing in an individually metered dwelling unit when that customer establishes that discontinuance of service will result in some person residing at that residence becoming seriously ill or more seriously ill if the service is discontinued. Any customer seeking to avoid termination of service under this section must make a written request supported by a written statement from a licensed physician. Both the request and the statement must be received by the utility not more than five working days after the date of delinquency of the bill. The prohibition against service termination provided by this section shall last 20 days from the date of receipt by the utility of the request and statement or such lesser period as may be agreed upon by the utility and the customer. The customer who makes such request shall sign an installment agreement which provides for payment of such service along with timely payments for subsequent monthly billings.

(5) Applicant deposit.

(A) Establishment of credit for residential applicants. Each utility may require a residential applicant for service to satisfactorily establish credit but such establishment of credit shall not relieve the customer from complying with rules for prompt payment of bills. Subject to these rules, a residential applicant shall not be required to pay a deposit:

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

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

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

(B) Reestablishment of credit. Every applicant who has previously been a customer of the utility and whose service has been discontinued for nonpayment of bills shall be required before service is rendered to pay all his amounts due the utility or execute a written deferred payment agreement, if offered, and reestablish credit as provided in subparagraph (A) of this paragraph.

(C) Amount of deposit and interest for residential service, and exemption from deposit.

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

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

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

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

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

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

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

(E) Records of deposits.

(i) The utility shall keep records to show:

(I) the name and address of each depositor;

(II) the amount and date of the deposit; and

(III) each transaction concerning the deposit.

(ii) The utility shall issue a receipt of deposit to each applicant from whom a deposit is received and shall provide means whereby a depositor may establish claim if the receipt is lost.

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

(F) Refund of deposit.

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

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

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

(H) Complaint by applicant or customer. Each utility shall direct its personnel engaged in initial contact with an applicant or customer for service seeking to establish or reestablish credit under the provisions of these rules to inform the customer, if dissatisfaction is expressed with the utility's decision, of the customer's right to file a complaint with the regulatory authority thereon.

(6) Billing.

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

(B) The customer's bill must show all the following information. The information must be arranged and displayed in such a manner as to allow the customer to compute his bill with the applicable rate schedule. The applicable rate schedule must be mailed to the customer on request of the customer. A utility may exhaust its present stock of nonconforming bill forms before compliance is required by this section:

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

(ii) the number and kind of units billed;

(iii) the applicable rate schedule title or code;

(iv) the total base bill;

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

(vi) the date by which the customer must pay the bill to get prompt payment discount;

(vii) the total amount due before and after any discount for prompt payment within a designated period;

(viii) a distinct marking to identify an estimated bill.

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

(D) Disputed bills.

(i) In the event of a dispute between the customer and the utility regarding the bill, the utility must forthwith make such investigation as is required by the particular case and report the results thereof to the customer. If the customer wishes to obtain the benefits of clause (ii) of this subparagraph, notification of the dispute must be given to the utility prior to the date the bill becomes delinquent. In the event the dispute is not resolved, the utility shall inform the customer of the complaint procedures of the appropriate regulatory authority.

(ii) 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.

(7) Meters.

(A) Meter requirements.

(i) Use of meter. All gas sold by a utility must be charged for by meter measurements, except where otherwise provided for by applicable law, regulation of the regulatory authority, or tariff.

(ii) Installation by utility. Unless otherwise authorized by the regulatory authority, each utility must provide and install and will continue to own and maintain all meters necessary for measurement of gas delivered to its customers.

(iii) Standard type. No utility may furnish, set up, or put in use any meter which is not reliable and of a standard type which meets generally accepted industry standards; provided, however, special meters not necessarily conforming to such standard types may be used for investigation, testing, or experimental purposes.

(B) Meter records. Each utility must keep the following records:

(i) Meter equipment records. Each utility must keep a record of all its meters, showing the customer's address and date of the last test.

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

(iii) Meter readings--meter unit location. In general, each meter must indicate clearly the units of service for which charge is made to the customer.

(iv) Meter tests on request of customer.

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

(II) Notwithstanding subclause (I) of this clause, if the meter is found to be more than nominally defective, to either the customer's or the utility's disadvantage, any fee charged for a meter test must be refunded to the customer. More than nominally defective means a deviation of more than 2.0% from accurate registration.

(v) Bill adjustments due to meter error.

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

(-a-) the last six months; or

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

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

(8) New construction.

(A) Standards of construction. Each utility is to construct, install, operate, and maintain its plant, structures, equipment, and lines in accordance with the provisions of such codes and standards as are generally accepted by the industry, as modified by rule or regulation of the regulatory authority or otherwise

by law, and in such manner to best accommodate the public and to prevent interference with service furnished by other public utilities insofar as practical.

(B) Line extension and construction charges. Every utility must file its extension policy. The policy must be consistent, nondiscriminatory, and is subject to the approval of the regulatory authority. No contribution in aid of construction may be required of any customer except as provided for in extension policy.

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

WEST TEXAS GAS UTILITY, LLC **RATE SCHEDULE**
Page 1 of 1 **RCE-INC**
Effective: ____________

RATE CASE EXPENSE SURCHARGE – INCORPORATED

APPLICABILITY

All jurisdictional customers in the incorporated areas or cities in West Texas Gas Utility, LLC's ("WTGU") Texas Service Area.

RCE RATE

Pursuant to City ordinances or an order of the Railroad Commission of Texas in Case No. OS-24-00017816, WTGU is authorized to recover a total not to exceed $___ in rate case expenses from Case No. OS-24-00017816 jurisdictional customers by a surcharge applicable to all jurisdictional customers in incorporated and unincorporated areas at the rate of $0.___/Mcf for a period of approximately ___ months commencing _________.

COMPLIANCE

WTGU shall file an Annual Compliance Report with the Cities identified above annually, due on or before the ___ of each ______ commencing in _________. The report shall detail the monthly collections for the rate case expense surcharge and show the outstanding balance. The Compliance Report shall be addressed to the City Manager.

WEST TEXAS GAS UTILITY, LLC **RATE SCHEDULE**
Page 1 of 1 **R-INC**
Effective: ____________

RESIDENTIAL SERVICE RATE – INCORPORATED

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 in an incorporated area or city served by West Texas Gas Utility, LLC. ("WTGU"). A residential consumer includes an individually-metered residential unit or dwelling and builders prior to sale or re-sale of a property for domestic purposes. This rate is only available to full requirements customers of WTGU.

COST OF SERVICE RATE

During each monthly billing period:

Subject to applicable rate adjustment provisions listed below, the following rates are applicable to Residential consumers per meter billing cycle or for any part of a billing cycle for which gas service is available at the same location.

Customer Charge	$29.50
All Consumption @	$7.68 per Mcf

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

OTHER FEES

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 Gas Cost Adjustment-INC.

Rate Case Expense Rider: Adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE- INC.

Taxes: Plus applicable taxes and fees related to above.

Pipeline Safety and Regulatory Program Fee: Adjustments in accordance with the provisions of Rate Schedule Pipeline Safety Fee- INC.

Miscellaneous Fees and Deposits: Adjustments in accordance with the provisions of Rate Schedule MISCFEE- INC.

Other Surcharges: Adjustments in accordance with the provisions of the Other Surcharges Rate Schedule OS- INC.

Winter Storm Rider: Surcharge for recovery of extraordinary gas costs caused by Winter Storm Uri in accordance with Rate Schedule WINTER STORM RIDER.

WEST TEXAS GAS UTILITY, LLC **RATE SCHEDULE**
Page 1 of 1 **TAX-INC**
Effective: ____________

TAX ADJUSTMENT – INCORPORATED

REVENUE RELATED TAX ADJUSTMENT

Each monthly bill for a jurisdictional customer, as adjusted, shall also be adjusted by an amount equivalent to the various revenue related taxes, franchise fees, rentals, or other fees and charges imposed by regulatory or governmental authorities. This includes, but not limited to, Gross Receipts Taxes, Municipal Taxes, Fees, or any other governmental imposition, rental fee or charge levied that is based on any portion of revenues billed by West Texas Gas Utility, LLC.

WINTER STORM URI SURCHARGE

APPLICABILITY

All Jurisdictional customers in the incorporated areas or cities in West Texas Gas Utility, LLC's ("WTGU") Texas Service Area.

PURPOSE

The purpose of the Winter Storm Uri Surcharge is to authorize WTGU to recover the reasonable, necessary, and prudent extraordinary gas costs incurred by WTGU as a result of Winter Storm Uri. The rate schedule is authorized by the Railroad Commission of Texas's ("Commission") Final Order in Case No. OS-24-00017816 and by cities that approved the corresponding request WTGU made with incorporated regulatory authorities, which approved a Winter Storm Uri Regulatory Asset and the recovery of the costs contained in the regulatory asset through a monthly surcharge. WTGU is authorized and directed to assess the Winter Storm Uri Surcharge rate as set forth in the section below.

SURCHARGE RATE

All Mcf during each billing period: $0.41 per Mcf.

This rate will be in effect until all approved and expended Winter Storm Uri costs, up to $3,502,862.41 ("Regulatory Asset Amount"), are recovered under the applicable rate schedules. Any excess recovery of the Regulatory Asset Amount shall be calculated and refunded to customers through a final true-up under this rate schedule.

OTHER ADJUSTMENTS

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

CONDITIONS

1. Subject to all applicable laws and orders, and WTGU's rules and regulations on file with the regulatory authority.
2. Uncollectible amounts, actually written off, associated with this surcharge shall be added back to the balance to be recovered via this surcharge.

3. Any amounts that were included in the Regulatory Asset Amount that are refunded to WTGU subsequent to the Final Order in Case No. OS-24-00017816 shall be subtracted from the balance and shall not be recovered via this surcharge.

WINTER STORM URI SURCHARGE RECOVERY COMPLIANCE REPORT

WTGU shall file a reconciliation report annually on or before March 31, commencing in 2026 and ceasing after a reconciliation report is filed at the end of the month following the month in which the Regulatory Asset Amount is fully recovered via the final reconciliation true-up (if applicable). WTGU shall file the report with the Commission, addressed to the Director of the Oversight and Safety Division and referencing Case No. OS-24-00017816, Winter Storm Uri Surcharge Recovery Report. The report shall include:

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

Reports for the Commission should be filed electronically at GUD_Compliance@rrc.texas.gov or at the following address:

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

BASE RATE REVENUE COMPARISON AT CURRENT, COST-BASED, AND PROPOSED RATES

		Current Base Rates			Proposed Base Rates	
Description	**Reference**	**Unadjusted**	**Weather Adjustment**	**Adjusted**	**Proposed**	**% Increase**
Domestic Customers						
Number of Domestic Customers	Schedule K	17,924		17,924	17,924	
Months per year		12		12	12	
Annual No. of Bills		215,084		215,084	215,084	
Domestic Customer Charge		**$ 23.42**		**$ 23.42**	**$ 29.50**	**26.0%**
Monthly Customer Charge Revenues		**5,037,267**		**5,037,267**	**6,344,978**	
Domestic Volumes -- Mcfs	Schedule K	1,007,056	56,179	1,063,235	1,063,235	
Domestic Consumption Charge		**$ 4.84**		**$ 4.84**	**$ 7.68**	**58.7%**
Consumption Charge Revenues		**4,874,153**		**5,146,057**	**8,165,644**	
Total Domestic Revenues		**9,911,420**		**10,183,324**	**14,510,622**	**42.5%**
Non-Domestic Customers						
Number of Non-Domestic Customers	Schedule K	2,484		2,484	2,484	
Months per year		12		12	12	
Annual No. of Bills		29,805		29,805	29,805	
Non-Domestic Customer Charge		**$ 43.57**		**$ 43.57**	**$ 79.00**	**81.3%**
Monthly Customer Charge Revenues		**1,298,604**		**1,298,604**	**2,354,595**	
Non-Domestic Volumes -- Mcfs	Schedule K	601,671	32,693	634,364	634,364	
Non-Domestic Consumption Charge		**$ 2.69**		**$ 2.69**	**$ 4.89**	**81.8%**
Consumption Charge Revenues		**1,618,495**		**1,706,440**	**3,102,041**	
Total Non-Domestic Revenues		**2,917,099**		**3,005,044**	**5,456,636**	**81.6%**
TOTAL JURISICTIONAL REVENUES		**12,828,519**		**13,188,368**	**19,967,258**	**51.4%**

Average Monthly Bill Impact

Customer Class (Zone)	Current Average Monthly Bill Including Gas Cost (a)(b)	Proposed Average Monthly Bill Including Gas Cost (b)	Proposed Monthly Dollar Change	Proposed Monthly Percentage Change
Domestic				
North	$ 73.96	$ 96.83	$ 22.87	30.9%
West	$ 60.83	$ 80.67	$ 19.84	32.6%
South	$ 42.50	$ 55.33	$ 12.83	30.2%
Non-Domestic				
North	$ 164.10	$ 240.97	$ 76.86	46.8%
West	$ 179.22	$ 268.22	$ 89.01	49.7%
South	$ 184.46	$ 272.60	$ 88.14	47.8%

(a) Current rates include WTGU's pending requested Gas Reliability Infrastructure Program charge.
(b) The cost of gas included in current and proposed monthly bills is the average by zone during the 2023 test year.

CASE NO. 00017816

STATEMENT OF INTENT OF WEST TEXAS GAS UTILITY, LLC TO INCREASE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF TEXAS	§ § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

JACK J. KING

ON BEHALF OF

WEST TEXAS GAS UTILITY, LLC

July 16, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF JACK J. KING

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jack J. (JJ) King. My business address is 303 Veterans Airpark Lane, Suite 5000, Midland, Texas 79705.

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

A. I am employed by West Texas Gas Utility, LLC ("WTGU" or the "Company") as the Vice President of Gas Marketing. (WTGU, formerly known as West Texas Gas, Inc. ("WTG-Inc.")), changed entity names through a merger in September 2021.)

Q. WHAT ARE YOUR DUTIES AS THE VICE PRESIDENT OF GAS MARKETING?

A. I am one of the corporate officers responsible for the utility pipeline operations of WTGU and its subsidiaries with operations in Texas and Oklahoma, handling marketing, business development, contract negotiations, contract administration, financial performance, and relationships with cities served by WTGU.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a bachelor's degree in Business Administration from Abilene Christian University in 1994. From 1994 to 1996, I was the Sales Coordinator for Compressor Systems, Inc. I joined WTG-Inc. in May 1996 as the Gas Contracts Administrator, and I was promoted to Gas Marketing Manager in 2000. In February 2016, I was promoted and elected to become an officer of WTG-Inc. with the title Vice President, Gas Marketing. Effective August 31, 2021, pursuant to a merger, all of WTG-Inc.'s assets were conveyed to a newly formed entity, WTGU, by the owner of WTG-Inc., the James L. Davis Estate (the "Merger"). Contemporaneously with the Merger, I was appointed as WTGU's Vice President, Gas Marketing (i.e., the same officer position that I held with WTG-Inc. prior to the Merger).

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I testified before the Railroad Commission of Texas ("Commission") in Gas Utilities Docket ("GUD") No. 9488 Consolidated and other cases before the Commission, including the Company's prior rate cases, GUD No. 10235 in 2013 and Docket No. OS-20-00004347, in 2020. I have also appeared before the Oklahoma Corporation Commission and various Texas municipalities in rate and other regulatory proceedings.

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 exhibits listed in the table of contents.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to:

- provide an overview of WTGU's service territory, operations and customer base;
- explain the reasons WTGU is filing a rate case at this time;
- support the prudence of the Company's capital investment through December 31, 2023;
- address employee compensation and benefits issues along with other expense items;
- explain WTGU's affiliate transactions and affiliate entities;
- address the proposed tariffs the Company is requesting, including the Gas Cost Adjustment ("GCA") clause;
- describe WTGU's gas supply protocol and the advantages of combining WTGU's gas supply efforts with affiliated entities; and
- support recovery of the Company's extraordinary gas costs related to Winter Storm Uri.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. I am co-sponsoring the following schedules and my testimony supports the reasonableness and necessity of the costs reflected in all of these schedules:

B-1 Operations and Maintenance Expenses

B-2 Administrative and General Expenses

H-1 Payroll Summary

H-2 Payroll Analysis

H-3 Bad Debts

H-4 Advertising Expenses

H-5 Donation and Contributions

H-6 Lobbying Expenses

H-7 Penalties and Fine

H-8 Outside Services Charged to A&G Accounts

H-9 Legal Expense Detail

H-10 Lost and Unaccounted for Gas

I-1 Organizational Chart

I-2 Charges by Affiliates to WTGU

I-3 Charges by Affiliates to Others

Q. PLEASE IDENTIFY THE COMPANY'S OTHER WITNESSES WHO ARE TESTIFYING IN SUPPORT OF THE COMPANY'S APPLICATION.

A. In addition to my direct testimony, the following witnesses are testifying on WTGU's behalf:

- Amanda Edgmon, Treasurer/Secretary also serving as WTGU Regulatory Accountant, addresses the Company's books and records; attests to the financial information contained in the Company's schedules; sponsors the Company's Gas Reliability Infrastructure Program ("GRIP") filings; discusses the proposed change to the factor to be used in future GRIP filings to determine the amount of capital investment that should be allocated to or recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers; presents the calculation of the regulatory asset amount related to Winter Storm Uri; and explains the corporate cost allocation method and services from some affiliates.

- Matthew Smith, Associate Vice President of Operations, provides an overview of field operations and expenses and supports the Company's rationale for its request to modify the factor used to determine what portion of the Company's capital investment will be recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers.

- Dane A. Watson, with Alliance Consulting Group, sponsors the depreciation study that he performed that produces the depreciation rates used to determine the Company's depreciation expense.

- Dr. Bruce H. Fairchild, Principal with Financial Concepts and Applications, Inc., sponsors the Company's cost of service schedules, requested capital structure and return on equity, overall rate of return, billing determinants, income tax expense and other tax issues, cost allocation and rate design; and presents the Company's proposed method for direct assignment of costs attributable to Jurisdictional Customers and Non-Jurisdictional Customers.

III. OVERVIEW OF WTGU

Q. PLEASE DESCRIBE WTGU.

A. WTGU is a Texas limited liability company as of September 1, 2021, headquartered in Midland, Texas. WTGU is not publicly traded on any stock exchange. WTGU is a natural gas utility in the States of Texas and Oklahoma that owns and operates gas distribution, gathering, and transmission pipeline systems. WTGU has affiliate entities in six states involved in natural gas marketing, intrastate and interstate gas transmission facilities, oil and gas exploration and production, gas gathering and processing facilities, and refined products distribution. WTGU's gas distribution facilities in Texas are located in seventy-three Texas counties and currently serve more than 23,500 domestic and non-domestic jurisdictional, and irrigation and agricultural non-jurisdictional customers. A Texas System Map is attached as Exhibit JJK-1.

Q. PLEASE EXPLAIN THE NATURE AND EXTENT OF WTGU'S UTILITY OPERATIONS IN TEXAS.

A. WTGU's utility operations began in 1976 with the acquisition of three rural natural gas systems primarily serving a few hundred irrigation and residential customers along a Northern Natural Gas transmission mainline running from the Permian Basin to the northern Texas Panhandle. WTGU has grown its local distribution company ("LDC") operations through numerous acquisitions and pipeline construction projects. Today, WTGU operates nearly 6,000 miles of distribution mains serving approximately 29,000 residential, commercial, irrigation and agricultural customers in Texas and Oklahoma.

Q. **WHERE IS WTGU'S PRINCIPAL OFFICE LOCATED?**

A. WTGU's principal office is located at 303 Veterans Airpark Lane, Suite 5000, Midland, Texas. All corporate, legal, and accounting records of WTGU are maintained at this principal office or located in nearby storage facilities. WTGU also maintains regional field operations offices in Fort Stockton, Lubbock, Junction, Canadian, Amarillo, Dalhart, and Lytle, Texas along with an office in Guymon, Oklahoma. WTGU also has several small field offices serving WTGU's Texas service area.

Q. DOES WTGU OWN ANY TRANSMISSION LINES IN TEXAS?

A. Yes. WTGU operates 752 miles of transmission pipeline in Texas that are used to supply downstream WTGU distribution facilities and a few end-use or resale customers. WTGU's affiliates WTG Gas Transmission Company, LLC ("WTGGT") and Western Gas Interstate Company, LLC ("WGI"), are regulated by the Commission or the Federal Energy Regulatory Commission ("FERC"), and operate 710 miles and 67 miles, respectively, of transmission pipelines in Texas.

Q. ARE WTGU'S TRANSMISSION PIPELINES THAT ARE OPERATED BY AFFILIATES SHOWN ON THE TEXAS SYSTEM MAP?

A. Yes. WTGGT and WGI intrastate and interstate transmission pipeline systems are shown on Exhibit JJK-1.

Q. DOES WTGGT OR WGI TRANSPORT ANY GAS TO WTGU'S DISTRIBUTION SYSTEMS?

A. Yes, there are a few WTGU distribution systems that are served upstream by WTGGT or WGI. In these instances, both WTGGT and WGI charge only their

FERC or Commission-approved tariff rates, which WTGU recognizes as an allowed gas cost element and includes these transport charges in WTGU's monthly GCA clause.

Q. IS WTGU DIFFERENT FROM OTHER TEXAS GAS UTILITY COMPANIES?

A. Yes. WTGU is much smaller, and therefore quite different, from the larger natural gas utility companies that operate in Texas.

- As was true in our last rate case, a significant portion of WTGU's load profile continues to consist of non-jurisdictional agricultural markets. These markets are largely composed of interruptible short-term service agreements where customers pay no demand charges and have no minimum throughput requirements.
- Due to the portion of non-jurisdictional customers WTGU serves, a recurring regulatory issue is what portion of ongoing investment should be recovered from jurisdictional customers regulated by the Commission and cities WTGU serves. Currently, WTGU is authorized to recover from jurisdictional customers a little more than one-third of its overall ongoing capital investment, which understates the level of investment the Company makes to serve jurisdictional customers. This rate treatment affects the return the Company is able to earn on its investment.
- Even though WTGU serves areas of new development in the Amarillo, Lubbock, and San Antonio areas, WTGU's jurisdictional customers are generally located in small rural municipalities and rural environs. The Company has nearly 6,000 miles of distribution pipelines situated in seventy-three Texas counties. WTGU's average miles of pipeline per customer meter and cost of service per customer are likely higher than a gas utility serving large metropolitan areas, which are much more densely populated.
- Due to the Company's limited staff, WTGU's management and supervisory personnel are responsible for a wide range of duties. Risk management, legal, safety training, fleet management, engineering and drafting, rate regulation, and other functions are shared by a limited number of staff members, or outside consultants must be retained.

Q. PLEASE ELABORATE ON THE DIFFERENCES BETWEEN WTGU'S OPERATIONS IN LARGELY RURAL AREAS WITH LOW CUSTOMER DENSITY COMPARED TO OTHER LDCS IN TEXAS.

A. Based on 2023 data, WTGU serves an average of 6 customers per mile of pipeline, whereas the Texas LDC that is next closest in size to WTGU serves an average of 39 customers per mile of pipeline. An average calculation for several LDCs throughout the state shows the average is 53 customers per mile of pipeline.[1]

Similar differences exist for the number of service lines per mile of pipeline, as shown in the table below. WTGU averages just over 6 service lines per mile of pipeline, whereas the average for LDCs throughout the state is just over 53 service lines per mile.

	Total Miles of Main	**Total Service Lines**	**Service Lines/Mile**
West Texas Gas Utility	4,861	29,795	6
Atmos Energy - West Texas	8,763	339,797	39
SiEnergy	1,076	52,949	49
Atmos Energy - Mid-Tex	32,448	1,808,445	56
CenterPoint Energy	35,201	2,010,363	57
CoServ Gas	2,460	149,019	61
Texas Gas Service	11,121	712,587	64
Average Service Lines Per Mile	95,930	5,102,955	53

[1] 2023 PHMSA Annual Gas Distribution Report. The averages were calculated for WTGU, Atmos Energy (Mid-Tex and West Texas Divisions), SiEnergy, CenterPoint Energy, CoServ Gas and Texas Gas Service Company.

Q. WHO REGULATES THE RATES, OPERATIONS AND ACCOUNTING PRACTICES OF WTGU?

A. WTGU's gas distribution rates are regulated by the cities in which it provides service and the Commission. Pipeline safety regulations issued and enforced by the Commission and the US Department of Transportation apply to WTGU's pipeline operations. The Commission has adopted FERC's Uniform System of Accounts ("USOA") for accounting reporting purposes and WTGU complies with this reporting system, which Company witness Amanda Edgmon addresses in her direct testimony.

Q. DOES WTGU USE GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP") IN THE ORDINARY COURSE OF BUSINESS?

A. Yes. Due to bank loan covenants, WTGU and its affiliates are required to maintain their books and records in accordance with GAAP. Therefore, WTGU and its affiliates utilize a common accounting software system, chart of accounts, and financial reporting software to satisfy the GAAP requirement. WTGU utilizes a cross reference to its chart of accounts for FERC accounting and reporting purposes. WTGU files all regulatory reports and annual filings on a FERC accounting basis. The schedules contained in this rate filing all use the FERC USOA.

IV. WTGU CUSTOMER BASE

Q. PLEASE DESCRIBE WTGU'S JURISDICTIONAL CUSTOMER CLASSES.

A. WTGU has two jurisdictional customer classes: domestic and non-domestic customers as follows:

Domestic Customers	Non-Domestic Customers
Residential	Commercial Public Authority Non-Profit

Q. HOW MANY DOMESTIC AND NON-DOMESTIC CUSTOMERS ARE SERVED BY WTGU IN TEXAS?

A. As of December 31, 2023, WTGU has a total of 20,407 jurisdictional Texas customers consisting of 17,923 domestic and 2,485 non-domestic customers. WTGU's number of municipal and environs jurisdictional customers in Texas is as follows:

	Domestic	Non-Domestic	Total
Environs	5,747	475	6,222
Municipal	12,176	2,010	14,186
Total	17,923	2,485	20,407

Q. HAS THE NUMBER OF JURISDICTIONAL CUSTOMERS GROWN SINCE THE LAST RATE CASE?

A. Yes. The number of customers served by WTGU has slowly grown since the 2020 rate case. The following chart shows WTGU's customer count at December 31 for each year from 2019 through 2023.

	Domestic	Non-Domestic	Total
2019	15,725	2,228	17,953
2020	15,937	2,233	18,170
2021	16,597	2,371	18,968
2022	17,048	2,523	19,571
2023	17,923	2,485	20,407

Q. WHAT FACTORS HAVE CONTRIBUTED TO WTGU'S INCREASE IN CUSTOMERS WITHIN TEXAS?

A. As was true in the last rate case, growth in the environs areas south and southwest of Amarillo and north of the City of Canyon, and continued extensions into new subdivisions in the Lubbock and San Antonio areas, are driving growth. At the same time, several areas served by WTGU in the smaller rural municipalities and their environs have experienced negative growth.

Q. DOES WTGU EXPECT CUSTOMER GROWTH TO CONTINUE?

A. Yes. The population growth that is occurring in and around the cities of Amarillo, Canyon, Lubbock, San Antonio and south of Austin is expected to continue, which will create slow yet steady growth for WTGU. In addition, the Company is open to acquiring small utility systems that fit in or around our current geographical footprint and align well with WTGU's current operations.

Q. WHAT IS THE AVERAGE MONTHLY CONSUMPTION FOR WTGU'S TEXAS JURISDICTIONAL CUSTOMERS?

A. During the test year, the average monthly unadjusted consumption for domestic customers was 4.7 Mcf and 20.18 Mcf for non-domestic customers.

V. <u>PURPOSE OF RATE CASE FILING</u>

Q. WHY IS WTGU FILING A RATE CASE AT THIS TIME?

A. There are a few primary reasons WTGU is filing a rate case right now. First, the Company's existing rates are not sufficient to allow it a reasonable opportunity to earn a reasonable return on its investment. This is a result of a few factors, including that the costs of doing business have increased in the last five years, substantial ongoing Distribution Integrity Management Program ("DIMP") work necessitating supervision and capital investment, and prior rate decisions that limit the cost of service that can be recovered from jurisdictional customers.

Relatedly, another reason WTGU is filing a rate case is to better align the investment it makes and cost recovery from customers who benefit from the investment. Specifically, in the Company's 2013 and 2020 rate cases, the Commission approved a "jurisdictional allocation factor" that caps the percentage of capital investment costs the Company can recover from jurisdictional customers in the rate cases as well as in GRIP filings. In the last rate case, the approved percentage was 36.75% and the parties agreed the jurisdictional allocation factor would be analyzed further in the Company's next rate case. These issues adversely impact the Company's ability to earn its allowed rate of return for the service WTGU provides to jurisdictional customers.

Finally, the Company is seeking recovery of the extraordinary gas costs it incurred to maintain and provide service to customers during Winter Storm Uri in February 2021. WTGU has not recovered any of those costs and did not participate in the securitization proceeding the Commission oversaw in 2021 and 2022.

Q. DOES WTGU TAKE STEPS TO CONTROL ITS OPERATING COSTS?

A. Yes, however WTGU's single largest cost of service item is personnel costs. WTGU would not be able to provide customers with the safe and reliable service it provides without a sufficient number of employees who must be compensated in a reasonable way. The Company's number of employees, employee pay rates, and related personnel benefits compare favorably to other Texas distribution utilities. As a privately held utility, WTGU is also very cost-conscious. WTGU also avoids some costs incurred by publicly traded utilities, such as Securities and Exchange Commission related compliance and reporting expenses as well as stockholder relations expenses.

Q. PLEASE DESCRIBE THE STATEMENT OF INTENT FILINGS MADE BY WTGU.

A. WTGU filed its Statements of Intent with the Commission and its thirty-six (36) municipalities on July 16, 2024, using a test year ending December 31, 2023.

Q. ARE THERE ANY CITIES THAT HAVE SURRENDERED THEIR ORIGINAL JURISDICTION TO THE COMMISSION?

A. No.

Q. PLEASE DESCRIBE WTGU'S PROPOSED RATE INCREASE.

A. WTGU proposes an approximately $6.8 million revenue increase for its jurisdictional customers with the intent of continuing to use generally applicable statewide rates in Texas, which includes incorporated and environs areas in which WTGU operates. The use of statewide rates was initially approved in WTGU case, GUD No. 9488 Consolidated, and the Commission-approved statewide rates in WTGU's last rate proceedings in GUD No. 10235 and Docket No. OS-20-00004347.[2] The continuation of a uniform statewide rate structure for WTGU customers, along with continued recognition of the differences in the cost of gas in

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[2] *Statement of Intent Filed by West Texas Gas, Inc., to Increase Special Rates in the Unincorporated Towns and Rural Areas, Environs, and Appeals from the Decisions of the Cities of Balmorhea, Claude, Darrouzett, Eden, Farwell, Follett, Groom, Higgins, Junction, Menard, Miami, Mobeetie, Shamrock, Stratford, Texhoma, Wheeler, Paint Rock, Cactus, Canadian, Kermit, Natalia, Somerset, Sonora, and Texline,* GUD No. 9488, Final Order at Finding of Fact No. 19 and Conclusion of Law No. 3 (Nov. 23, 2004); *Statement of Intent of West Texas Gas, Inc. to Increase Gas Distribution Rates in the Unincorporated Areas of Texas*, GUD No. 10235, Final Order (Jun. 13, 2013); *Statement of Intent of West Texas Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of Texas*, Docket No. OS-20-00004347 consol., Final Order (Feb. 9, 2021).

the various regions that WTGU serves, will help ensure that all customers pay rates that reflect WTGU's actual cost of service.

Q. WHAT IS THE IMPACT OF THE PROPOSED RATES ON DOMESTIC AND NON-DOMESTIC CUSTOMERS IN TEXAS?

A. Inclusive of a $3.40 per Mcf average cost of gas during the test year, a typical domestic customer using 6 Mcf in a billing period will experience an increase of $23.12, or 31.7%. A domestic customer is one whose natural gas service is individually metered and typically refers to residential service. Using the same average cost of gas, a non-domestic customer using 30 Mcf in a billing cycle will experience a $101.43, or 44.8%, increase. Non-domestic customers include commercial, industrial or non-profit customers.

Q. WILL THE RATES THE COMPANY IS REQUESTING ALLOW IT TO RECOVER THE FULL INCREASE IN ITS COST OF SERVICE AS SHOWN IN THE SCHEDULES PREPARED BY DR. FAIRCHILD?

A. No. Fully cost-based rates as calculated by Dr. Fairchild would create a very large rate increase for customers compared to current rates:

Description	Current Rates[3]	Cost-Based Rates	Percentage Change
Domestic Customers			
Customer Charge	$ 23.42	$ 71.63	205.8%
Commodity Charge (Mcf)	$ 4.84	$ 4.67	-3.6%
Non-Domestic Customers			
Customer Charge	$ 43.57	$ 82.89	90.2%
Commodity Charge (Mcf)	$ 2.69	$ 9.61	257.4%

[3] Includes customer charge amounts for the Company's GRIP filing made on May 17, 2024.

To moderate customer rate impacts, the Company is requesting rates that are less than necessary to recover the full cost of service as shown below. Even though the Company's increase in the cost of service supports the requested rate increase, the Company is aware that the requested rates represent a sizeable increase compared to current rates.

Description	Current Rates	Requested Rates	Percentage Change
Domestic Customers			
Customer Charge	$ 23.42	$ 29.50	26.0%
Commodity Charge (Mcf)	$ 4.84	$ 7.68	58.7%
Non-Domestic Customers			
Customer Charge	$ 43.57	$ 79.00	81.3%
Commodity Charge (Mcf)	$ 2.69	$ 4.89	81.8%

VI. RATE BASE

Q. PLEASE DESCRIBE WTGU'S TEST YEAR PROPERTY AND PLANT THAT IS INCLUDED IN THE COMPANY'S RATE BASE AMOUNTS.

A. WTGU's requested rate base, the amount on which a utility is entitled to earn a fair rate of return, is shown on Schedule C, with underlying rate base data shown on Schedules C-1 through C-5. As shown on Schedule C, rate base consists of WTGU's investment in property, plant and equipment, plus materials and supplies, less contributions in aid of construction provided by WTGU customers, and deferred income taxes. WTGU's investment includes assets exclusively serving customers in Texas and an allocated portion of assets serving customers in the Texas and Oklahoma service areas.

Q. PLEASE EXPLAIN WTGU'S ORIGINAL COST, ACCUMULATED DEPRECIATION AND NET BOOK COST CALCULATIONS TO DEVELOP THE COMPANY'S NET COST USED FOR PROPERTY, PLANT AND EQUIPMENT.

A. The original cost and accumulated depreciation of WTGU's property, plant, and equipment are reflected on Lines 13 and 14 of Schedule C, with detail of this property by FERC account being contained in Schedules C-1 and C-2, respectively. Schedule C reflects the test year-end balances for WTGU and adjustments made by Dr. Fairchild.

Q. DO THE TEST YEAR RATE BASE AMOUNTS INCLUDE COSTS PAID TO DEVELOPERS FOR ACCESS TO NEW DEVELOPMENTS IN WTGU'S SERVICE TERRITORY?

A. Yes. Increasingly, those types of costs have become a cost of doing business for the Company. While not all developers charge the Company these one-time fees, the fees for the ones who do charge typically range from $200 to $350 per lot depending on the location and level of competition in the area. In our experience, developers have also become fairly sophisticated in trying to create competition for utility access to a new subdivision or development, including whether the development will be served by a gas or an electric utility. The Company wants to grow its customer base, which helps generate a larger number of customers to spread the Company's costs over. Existing WTGU customers benefit from this growth, and the Company wants to continue to make natural gas an option for residences and local businesses. In addition, without gaining access to these new developments, there is a risk the related homes and businesses would be built to use all electric appliances and service, which is a higher-cost energy source than natural gas.

Q. HAS THE COMPANY MADE ANY ACQUISITIONS SINCE ITS LAST RATE CASE IN 2020?

A. Yes. WTGU acquired the City of Van Horn distribution system in May 2021.

Q. PLEASE DESCRIBE THE CITY OF VAN HORN ACQUISITION.

A. Effective May 1, 2021, WTGU acquired the City of Van Horn, Texas gas distribution system. This gas distribution system is situated mainly in the incorporated limits of the City of Van Horn and serves almost 745 jurisdictional domestic and non-domestic customers. This system is composed of about 17.05 miles of steel mainline and more than 6.6 miles of poly mainline and service laterals. The purchase price was less than the $1 million threshold in GURA § 102.051.

Q. DESCRIBE THE PROPOSED TREATMENT OF WTGU'S DIMP CAPITAL INVESTMENT.

A. Capital costs related to WTGU's DIMP are included in Schedule C-5 and are included as a part of WTGU's rate base. In addition, DIMP capital costs are included in each of WTGU's GRIP filings made since Docket No. OS-20-00004347, which Ms. Edgmon and Mr. Smith address in their testimonies. DIMP capital costs are an example of the type of investment that benefits jurisdictional customers, yet WTGU is not able to fully recover the amount of investment from jurisdictional customers due to the jurisdictional allocator approved in the last rate case. The same allocator is also applied to DIMP investment included in the Company's GRIP filings. As Ms. Edgmon explains in her testimony, going forward, the Company is requesting approval to recover all of the costs of jurisdictional investment from jurisdictional customers and none of the costs of non-jurisdictional investment from jurisdictional customers.

Q. PLEASE DESCRIBE THE MATERIALS AND SUPPLIES AMOUNTS SHOWN ON SCHEDULE C-3.

A. WTGU maintains pipe and other inventories at some of its larger field offices, including steel and poly pipe, regulators, meters, steel and poly fittings and valves, risers, anodes, marker signage, replacement parts for valves, regulators, and meters. WTGU has included $1.85 million as shown on Schedule C-3 for materials and supplies inventory. The calculations of the amount sought are sponsored by Dr. Fairchild.

Q. ARE ANY MATERIALS AND SUPPLIES COSTS RECOVERED THROUGH WTGU'S GCA CLAUSE?

A. No.

Q. PLEASE DESCRIBE THE TREATMENT OF CUSTOMER DEPOSITS SHOWN ON SCHEDULE C.

A. The balance of Customer Deposits reflected on Schedule C is included as a reduction of WTGU's rate base because WTGU pays interest on these customer deposits at the interest rate stipulated by the Public Utility Commission of Texas and adopted by the Railroad Commission.

Q. PLEASE EXPLAIN WTGU'S TREATMENT OF CONTRIBUTIONS IN AID OF CONSTRUCTION.

A. Typically, WTGU requires customer contributions in aid of construction for projects that do not qualify under WTGU's extension policy because it fails to meet minimum investment criteria (e.g., rate of return or capital investment thresholds) based on published tariff rates or standard non-jurisdictional rates. These contributions are amortized over the life of the related capital investment and used to offset depreciation expense on WTGU's books.

Q. WHAT IS WTGU'S RATE BASE?

A. The Company's rate base consists of invested capital that is used and useful in providing utility service to customers. Rate base is also used to determine the return portion of WTGU's cost of service, which is calculated by Dr. Fairchild.

Q. HAS WTGU INCLUDED AN ALLOWANCE FOR CASH WORKING CAPITAL AS A COMPONENT OF ITS RATE BASE?

A. No. To reduce rate case expenses, WTGU has not performed a lead lag study, so WTGU has not included any provision for cash working capital in the requested rate base amount.

Q. HAS THE COMPANY'S RATE BASE BEEN ADJUSTED FOR NON-INVESTOR SUPPLIED CAPITAL?

A. Yes. As reflected on Schedule C, WTGU's rate base has been adjusted for Customer Deposits, Contributions in Aid of Construction, Accumulated Deferred Income Taxes ("ADIT") and Excess ADIT. The calculation of the adjustments for non-investor supplied capital is sponsored by Dr. Fairchild.

Q. IS WTGU'S ENTIRE RATE BASE USED AND USEFUL FOR SERVING ITS CUSTOMERS?

A. Yes. Assets that are not used and useful have been removed from the rate base calculations. In addition to transmission assets and those assets identified with WTGU's Oklahoma operations, amounts related to acquisition premiums, non-utility assets, and out-of-service assets have also been removed from WTGU's rate base. Schedule A-3 and all of the C Schedules provide the details for these adjustments to rate base.

Q. IS THERE ANY PLANT, PROPERTY OR EQUIPMENT IN RATE BASE THAT COULD BE CLASSIFIED AS PLANT HELD FOR FUTURE USE OR CONSTRUCTION WORK IN PROGRESS?

A. No. There is no plant held for future use or construction work in progress included in WTGU's rate base. Out-of-Service plant, which might be considered gas plant for future use, has also been removed from rate base. All of WTGU's property, plant and equipment included in rate base is currently dedicated to serving WTGU customers.

VII. DEPRECIATION EXPENSE

Q. PLEASE DESCRIBE WTGU'S DEPRECIATION EXPENSE.

A. Consistent with the Commission's prior rulings in GUD No. 9488, and with the filings and rulings in GUD No. 10235 and Docket No. OS-20-00004347, the depreciation rates in this case are based upon a depreciation study. As it did in the last rate case, the Company retained Mr. Dane Watson of Alliance Consulting Services to conduct a depreciation study. His studies, conclusions, and recommendations are included in this rate case.

Q. AS A RESULT OF THE NEW DEPRECIATION STUDY, HOW MUCH IS WTGU SEEKING TO RECOVER IN DEPRECIATION EXPENSE?

A. WTGU is seeking to recover $5.2 million in depreciation expense from its jurisdictional customers as shown in Schedule D. Mr. Watson's testimony and depreciation study provide additional information to support this request.

VIII. RATE OF RETURN AND COST OF DEBT

Q. WHAT RATE OF RETURN WAS USED IN CALCULATING WTGU'S REVENUE REQUIREMENT?

A. As reflected in Schedule E, WTGU utilized a rate of return of 8.10% in calculating its revenue requirement. Please see the direct testimony of Dr. Fairchild supporting WTGU's proposed cost of capital and overall return.

Q. WHAT IS WTGU'S REQUESTED COST OF DEBT?

A. The weighted average cost of debt calculated on Schedule E is 1.05%. However, the cost of long-term debt included in this filing is 3.06% and is supported by Dr. Fairchild.

Q. WHAT BANKING INSTITUTIONS HAVE LOANED MONEY TO WTGU?

A. WTGU and its affiliates are parties to a credit facility provided by a syndicate of national and international banks lead by Mizuho. WTGU and its affiliates are jointly and severally liable for all outstanding amounts owed under this credit facility.

Q. DOES WTGU HAVE ANY OUTSTANDING DEBT?

A. Yes. As of December 31, 2023, WTGU's outstanding debt is $155,000,000 owed to the syndicate group of banks led by Mizuho.

IX. REVENUE AND EXPENSES

Q. PLEASE IDENTIFY ANY ADJUSTMENTS TO REVENUES.

A. The only adjustments to test year revenues are to weather normalized volumes for domestic and non-domestic customers as shown on Schedules A-2 and A-3. In addition, the current revenues included in the cost of service schedules include revenues related to the GRIP filing the Company made on May 17, 2024. Dr. Fairchild sponsors these calculations in the schedules.

Q. WERE THERE ANY ADJUSTMENTS FOR SALARY DECREASES OR TERMINATIONS?

A. No. There were no salary decreases or overall staff reductions during the test year. The payroll costs WTGU seeks to recover in this case are shown on Schedules H-1 and H-2 with adjustments summarized on Schedule A-3.

Q. WHAT STEPS DOES THE COMPANY TAKE TO ENSURE THAT ITS COMPENSATION FOR EMPLOYEES IS REASONABLE?

A. The Company operates in a geographic region where there is competition for experienced utility employees and other types of employees who are necessary to support typical corporate and business functions. To provide adequate compensation to attract and retain employees, the Company considers salary data for our industry, including information available from the U.S. Bureau of Labor Statistics. WTGU believes its salary scale is generally average, but below the level of some larger companies with identical positions in our service area. In addition to salary, employees are also eligible for bonuses.

Q. COULD WTGU RETAIN OR REPLACE ITS CURRENT STAFF WITH COMPARABLE EMPLOYEES WITHOUT THE COMPENSATION PAID TO EMPLOYEES?

A. No. The salary levels and bonuses awarded are necessary to retain and properly compensate employees with a competitive salary package when compared to similar positions with other companies in the Midland employment market. Employee retention is an important factor in controlling labor costs. Retention of long-term employees preserves institutional knowledge and experience, which enhances pipeline safety and service reliability. In addition, to the extent WTGU must hire new employees, the salaries it offers must be sufficient to compete with other employers.

Q. DOES WTGU FACE COMPETITION FROM OTHER EMPLOYERS IN THE REGION THAT REQUIRE THE SAME TYPES OF EMPLOYEES AS WTGU?

A. Yes. In addition to other utilities in the area, WTGU employees also have the experience and skill sets to work in non-regulated industries, especially dealing with oil and gas issues. Those types of jobs are in high demand not only in the immediate Midland area but also throughout the areas where WTGU provides service. There are regularly instances in which our employees are approached by other employers who are interested in hiring them away from WTGU. For these reasons, WTGU must take steps to retain existing employees including offering base pay and benefits that adequately compensate employees.

Q. DOES WTGU OFFER EMPLOYEES BENEFITS?

A. Yes. The Company provides traditional benefits such as health, dental and vision insurance, as well as paid time off and a 401(k). Benefits costs are shown on Schedule B-2.

Q. PLEASE DESCRIBE THE ADVERTISING EXPENSES SHOWN ON SCHEDULE H-4.

A. The majority of the advertising expenses shown on Schedule H-4 are costs incurred related to advertising in local area newspapers for employment ads. Costs also include advertisements in home builder publications as well as with local chambers of commerce.

Q. IS WTGU SEEKING TO RECOVER COSTS OF DONATIONS AND CONTRIBUTIONS MADE DURING THE TEST YEAR (SCHEDULE H-5)?

A. No. The donations and contributions amounts shown on Schedule H-5 have been removed from the Company's request in this case, which is also shown on Schedule A-3.

Q. IS WTGU REQUESTING RECOVERY OF PENALTIES AND FINES IDENTIFIED ON SCHEDULE H-7?

A. No, amounts for penalties or fines shown on Schedule H-7 have been removed from the rate request, as shown on Schedule A-3.

Q. WHAT IS WTGU'S POLICY REGARDING EMPLOYEE EXPENSES?

A. As part of the last rate case, WTGU agreed to submit a policy to Commission Staff that addresses employee expenses, which the Company did in March 2021. The General Employee Expense and Reimbursement Policy is designed to facilitate evaluation of employee expenses by the Commission and contains guidelines for reimbursable expenses that might be incurred while an employee is traveling to carry out his or her assigned duties or incurred while fulfilling a company responsibility or company function. Reimbursable expenses must be supported with an itemized receipt or invoice that indicates the goods or services provided and the individuals that received those goods or services. Exceptions are made to this guideline if the amount being reimbursed is considered immaterial, generally $25 or less. Acceptable entertainment is generally considered to be a meal with a customer, vendor, business associate, or subordinate employee.

Q. WHAT IS THE COMPANY'S TRAVEL POLICY?

A. Because most of WTGU's assets are situated in rural or remote areas of the state, automobile travel is the predominate method of travel for WTGU management and supervisory personnel. In addition, the General Employee Expense and Reimbursement Policy notes that travel expenses must include documentation of the purpose for the travel, a copy of the itinerary and identification of employees traveling. Regarding lodging, the policy addresses the types of rooms that should be booked and contains guidelines for reimbursable lodging costs.

Q. IS THE COMPANY REQUESTING RECOVERY OF TEST YEAR MEAL, LODGING AND ENTERTAINMENT EXPENSES?

A. No. All meal, lodging and entertainment expenses have been removed. The Company would have to engage in a time-intensive, manual review to exclude entertainment expenses and only amounts above the Commission's current meal and lodging thresholds. To reduce issues in controversy, the Company has made the decision to remove all meal, lodging and entertainment expenses.

Q. PLEASE DESCRIBE SCHEDULE H-9.

A. Schedule H-9 reflects legal fees paid to various attorneys during the test year. Those charges identified as Other Legal Matters pertain to fees incurred in the renegotiation and renewal of WTGU's credit facility with the Mizuho syndicate group, as well as fees paid for bad account collection, miscellaneous regulatory matters, and general corporate business.

X. LOST AND UNACCOUNTED FOR GAS

Q. PLEASE DESCRIBE SCHEDULE H-10.

A. Schedule H-10 reflects the lost and unaccounted for gas ("LUFG") volumes experienced by WTGU for the twelve-month period ending December 31, 2023. Any LUFG volumes from WTGU transmission systems have been eliminated in this schedule to reflect only the actual LUFG on WTGU's Texas distribution systems.

XI. AFFILIATE TRANSACTIONS

Q. PLEASE DESCRIBE THE STATUTORY STANDARD GOVERNING THE RECOVERY OF AFFILIATE EXPENSES.

A. Section 104.055 of GURA establishes that affiliate expenses must be reasonable and necessary and that the price charged to the gas utility not be higher than the price charged by the affiliate to its other affiliates, or to a non-affiliated person for the same items or class of items.

Q. IN YOUR OPINION, DO WTGU'S AFFILIATE EXPENSES MEET THE AFFILIATE STANDARD YOU JUST DESCRIBED?

A. Yes.

Q. ARE THE EXPENSE AMOUNTS WTGU PAID TO AFFILIATES DURING THE TEST YEAR REASONABLE AND NECESSARY?

A. Yes. WTGU does not pay any affiliate charges that exceed normal charges from arms-length third-party transactions.

Q. ARE THE PRICES WTGU PAID TO AFFILIATES HIGHER THAN PRICES CHARGED BY THE SUPPLYING AFFILIATE TO OTHER AFFILIATES OR NON-AFFILIATES FOR THE SAME ITEM OR CLASS OF ITEM?

A. No. The amounts paid by WTGU to affiliates are equal to, or less than, similar charges paid by non-affiliate entities.

Q. ARE AFFILIATE COSTS INCLUDED IN WTGU'S OPERATING EXPENSES?

A. Yes, affiliate expenses are as shown on Schedule I-2.

Q. ARE THE AFFILIATE COSTS ON SCHEDULE I-2 THE SAME TYPES OF AFFILIATE COSTS THAT WERE INCLUDED IN WTGU'S LAST RATE CASE?

A. Yes, and the Commission's final order in that case reflects the parties' agreement that the affiliate costs in the last rate case met the affiliate cost recovery standard.

Q. PLEASE DESCRIBE SCHEDULE I-1 AND THE NATURE OF WTGU, ITS AFFILIATES, PARENT, AND SUBSIDIARIES.

A. Schedule I-1 is an organization chart as of December 31, 2023, depicting the direct parent of WTGU and entities with which the Company had affiliate transactions during the test year. The chart contains wholly owned subsidiaries of WTG Downstream LLC, including WTG Fuels Holdings LLC, WTG Downstream Services, LLC ("WTGDS"), and WTG Downstream Holdings LLC ("WTG Downstream"), which is the direct parent entity of WTGU and is ultimately owned 80% by Stonepeak Remuda Investment Holdings LLC and 20% by the Estate of James L. Davis. The holding companies under WTG Downstream LLC are energy-related businesses (e.g., gathering, processing, transmission, gas marketing, and refined fuel retailer).

Q. FOR EACH AFFILIATE OF WTGU, PLEASE DESCRIBE THE NATURE OF ITS BUSINESS WITH WTGU DURING THE TEST YEAR.

A. As shown in Schedule I-2, test year charges paid to affiliates are as follows:

Line 11: WTG Gas Marketing, LLC ("WTGGM") provides gas procurement services to WTGU for nearly all of WTGU's distribution systems. WTG utilizes WTGGM for gas procurement in order to benefit from WTGGM's volumetric advantages (e.g., transportation discounts, imbalance accounting thresholds, and purchasing power). WTGGM does not markup its gas supply to WTGU. WTGGM gas cost is calculated and invoiced to WTGU at cost (inclusive of direct costs only, meaning costs of commodity, upstream transport, and balancing costs).

Gas supply from WTGGM is made available to WTGU at lower prices than gas supply available from third parties.

Line 14: WGI is the upstream interstate transmission pipeline operator that provides transportation service to several WTGU distribution systems in Sherman and Moore Counties, Texas. WTGU pays WGI for firm transportation service pursuant to WGI's FERC-approved tariff rates.

Lines 17-19: For approximately half of the test year, WTGU purchased a significant portion of its fleet gasoline and diesel supplies from WTG Fuels, LLC ("WTGF") by utilizing WTGF's GasCard fleet management system to control fuel usage in WTGU company vehicles. Vehicle fuel is usually purchased by WTGU personnel at retail sites that are owned and operated by third parties. Fuel is paid using the GasCard fleet system. The price WTGU paid to WTGF was the posted price that is offered to all retail customers at these sites, including other WTGU affiliates and non-affiliated third parties. In June 2023, Quarles Petroleum acquired WTGF, and WTGF is no longer an affiliate of the Company. Occasionally, WTGU purchases oils, lubes, or propane parts at a WTGF warehouse facility. These are usually small and inexpensive items that are purchased at the market price available to any WTGF affiliate or third party.

Line 25: WTGU receives administrative and other support services from WTGDS. This affiliate charge is addressed in more detail in testimony below and in Ms. Edgmon's direct testimony.

Q. ARE THERE ANY PAYMENTS MADE TO AFFILIATES DURING THE TEST YEAR THAT ARE NOT REFLECTED IN SCHEDULE I-2, AS AMENDED?

A. Yes. WTGU did not schedule out certain payments made to, or received from, affiliates that fall into two categories:

- Balance Sheet items that do not represent an income or expense item to WTGU or the affiliate (e.g., dividend payments); or
- An item paid to, or received from, affiliates that do not represent a revenue item to WTGU or the affiliate, but is an expense pass-through from a non-affiliated third party (e.g., vendors that combine goods or services to multiple companies on a single invoice, accounting errors where a vendor bills an incorrect company for goods or services).

Q. PLEASE DESCRIBE THE SUPPORT SERVICES PROVIDED BY WTGDS REFLECTED IN SCHEDULE I-2.

A. WTGDS provides various administrative personnel and necessary support services for WTGU's Midland administrative offices. For purposes of this rate case, the cost of items and support services from WTGDS were allocated among WTGU and affiliates. The allocation methodology is documented in a Cost Allocation Manual, which is discussed in direct testimony provided by Ms. Edgmon along with other information related to WTGDS.

Q. ARE THERE BENEFITS OF A CENTRALIZED CORPORATE SUPPORT SERVICE STRUCTURE?

A. Yes. Without the centralized corporate services provided by WTGDS, it would be necessary for WTGU to add administrative and professional staff positions to maintain its accounts payable, human resources, tax compliance, risk management, and information technology functions. By sharing these services with other affiliates, WTGU recognizes significant savings in salaries and related overhead.

Q. CONSIDERING THE ORGANIZATIONAL CHART IN SCHEDULE I-1 AND THE AFFILIATE TRANSACTIONS DURING THE TEST YEAR, DO YOU HAVE ANY OBSERVATIONS RELATED TO WTGU'S OPERATIONS UNDER A DIFFERENT CORPORATE STRUCTURE THAN THE ONE THAT EXISTED DURING THE LAST RATE CASE?

A. Even though the overall corporate structure surrounding WTGU has changed, that has not affected WTGU's operations and its continued focus on providing safe and reliable service to customers. WTGU still procures gas from WTGGM and still receives corporate support services from the same entity and employees it has for the last several years. In addition, the number of affiliate transactions decreased in 2023 compared to the test year in the Company's prior rate case.

XII. RATE CASE EXPENSE RECOVERY

Q. DOES WTGU SEEK RECOVERY OF REASONABLE RATE CASE EXPENSES?

A. Yes. Based on GURA § 104.051 and Commission Rule § 7.5530, WTGU seeks recovery of its reasonable rate case expenses as well as any reasonable rate case expenses WTGU reimburses to the cities affected by this rate filing. These expenses include costs for attorneys and consultants and other reasonable expenses the Company incurs associated with this case. WTGU requests that reasonable rate case expenses be recovered through a surcharge. The amount of costs to be recovered should be determined at a point during the case when those expenses have actually been incurred.

Q. WHAT IS THE STATUS OF THE COMPANY'S RECOVERY OF RATE CASE EXPENSES FROM THE LAST RATE CASE?

A. Since the final order was issued in the last rate case, WTGU has made annual compliance filings. As of May 31, 2024, WTGU must collect a remaining balance of $59,850.84. WTGU expects it will collect the remaining rate case expense balance by the end of 2024. WTGU plans to stop charging the surcharge when the amounts have been fully recovered, in accordance with the Rate Case Expense Surcharge rate schedules that were approved in the last rate case. If, for some reason, the Company has not fully recovered the authorized amount of rate case expenses, the Company will voluntarily discontinue the surcharge as of December 31, 2024.

XIII. GAS SUPPLY AND GAS COST ADJUSTMENT CLAUSE

A. Gas Cost Adjustment Clause

Q. HOW DOES WTGU RECOVER ITS COST OF GAS?

A. WTGU's Commission-approved GCA clause has several components that capture gas purchase costs, upstream transportation costs, and any applicable revenue-related taxes, fees, or other charges imposed by regulatory and governmental authorities. The GCA clause establishes how these gas cost components are calculated and passed through to customers. WTGU calculates a monthly gas cost estimate and updates its GCA on a monthly basis. WTGU provides the Commission with an annual reconciliation of actual gas costs versus the monthly estimated filings. Any over- or under-collection balances are calculated and correction factors are applied prospectively to ensure that WTGU collects only its allowed cost of gas.

Q. ARE ANY GAS COSTS INCLUDED IN THE MONTHLY CUSTOMER CHARGE OR CONSUMPTION CHARGE UNDER WTGU'S OTHER TARIFFS?

A. No. All gas costs are recovered through the GCA clause.

Q. IS WTGU PROPOSING ANY CHANGES TO ITS GCA CLAUSE?

A. No.

Q. IS THERE A NEED TO CONTINUE WTGU'S GCA CLAUSE?

A. Yes. The GCA clause was approved by the Commission in GUD No. 9488 Consolidated and has been in effect since then. The GCA clause functions well in today's gas markets. The continued use of WTGU's GCA clause operates to ensure that WTGU neither over-recovers nor under-recovers its cost of gas, and that WTGU customers pay only the Company's actual gas cost, including its authorized components.

Q. HOW ARE NATURAL GAS PRICES ESTABLISHED?

A. Natural gas is a commodity with the prices of natural gas established as a function of supply and demand. The availability of gas will affect prices. Increases in gas supply result in lower prices, and prices increase as supply decreases.

Q. WHAT ARE THE FACTORS THAT AFFECT THE PRICE OF DOMESTIC NATURAL GAS PRODUCTION?

A. On the supply side, variations in the amount of gas being produced, the amount of gas in storage and the amount of gas being imported or exported will affect prices. On the demand side, the factors that affect natural gas prices include the strength of the economy. A weak economy usually means lower prices and economic growth usually means higher prices. Weather is another important factor. Severe weather such as hurricanes and extreme low temperatures can affect supplies as well as demand. Winter weather has an effect on domestic and non-domestic customers. A third factor affecting demand for natural gas is the price of oil. Competition from other fuels can lead to large industrial and electrical generating customers switching fuels and the demand, or lack thereof, can affect prices. Other factors include pipeline capacity and pipeline outages.

Q. WILL THE PRICE FOR NATURAL GAS CONTINUE TO CHANGE?

A. Yes. All the factors that have caused historical price changes still exist, and changes in gas prices will continue into the future.

Q. DOES WTGU HAVE THE ABILITY TO CONTROL THE PRICES IT PAYS FOR GAS PURCHASES?

A. No. Prices for the commodity are established through a free market system based on supply and demand. WTGU has no control in establishing these gas prices. However, WTGU continually works to acquire a cost effective and reliable gas supply for its distribution systems.

B. Gas Supply Practices

Q. FROM WHAT ENTITIES DOES WTGU TYPICALLY PURCHASE GAS SUPPLY?

A. WTGU purchases a portion of its gas supply from suppliers that are directly connected to WTGU distribution systems, i.e., where there is no intermediary pipeline between WTGU and the supplier. DCP Midstream, Energy Transfer and Paisano Energy represent some of these direct WTG suppliers.

In addition, most of the gas that is delivered to WTGU distribution systems through upstream third-party transmission lines is supplied by an affiliate, WTGGM. WTGGM purchases natural gas supply from numerous affiliated and unaffiliated gas producers, gas processors, and natural gas marketing companies. Examples of unaffiliated gas producers and processors include Mercuria Energy, Energy Transfer, DCP Midstream, and Kinder Morgan. Examples of unaffiliated natural gas marketing companies include Oneok Energy Services, Tenaska Marketing, Conoco, Energy Transfer and Concord Energy.

Q. PLEASE EXPLAIN THE GAS PURCHASING PRACTICES USED TO SUPPLY WTG DISTRIBUTION SYSTEMS.

A. Generally, the daily gas supply requirements on the upstream pipelines serving WTGU's distribution systems are projected each month. These projections are based on historical quantities as well as current business and weather conditions. Once the projected requirements are determined, the supplies are purchased by WTGGM. These supplies are delivered into various upstream transmission systems and transported to WTGU's distribution systems. Some of these transporting pipelines include Atmos Energy, Oneok WesTex, El Paso Natural Gas, Northern Natural Gas, Colorado Interstate Gas, Kinder Morgan, and two WTGU affiliates, Western Gas Interstate Company and WTG Gas Transmission Company. Most of the gas supplies are purchased by WTGGM on a month-to-month base load basis at negotiated index-based or fixed prices. Some third-party supplies are purchased for longer terms at either negotiated index-based or fixed prices. Some daily gas purchases are made at Gas Daily published prices or fixed prices, as necessary, to meet contract balancing commitments on transporting pipelines upstream of WTGU systems.

Q. PLEASE EXPLAIN WHY A LARGER PORTION OF WTGU'S GAS SUPPLY IS NOT PURCHASED AT A FIXED PRICE FOR EXTENDED PERIODS OF TIME.

A. The goal is to purchase gas at prices that reflect the current market. Fixed price purchases for extended time periods invariably do not reflect the current market, making them difficult to explain to WTGU's customers. If WTGU purchased a large segment of its gas supply at a fixed price for long periods of time, it would not be able to purchase gas at market prices as the price of gas changes.

Q. DOES WTGU HEDGE THE PRICE OF ANY OF ITS GAS SUPPLY?

A. WTGU does not directly hedge the price of any gas supplies. However, on occasion, WTGU will request that WTGGM hedge its gas supply costs in order to provide WTGU with a fixed gas cost.

C. Affiliate Gas Supply Purchases

Q. DOES WTGU PURCHASE GAS FROM ANY AFFILIATES?

A. Yes, it does. WTGU purchases gas from WTGGM.

Q. HOW DO YOU DETERMINE A FAIR PRICE TO PAY FOR THE AFFILIATE GAS SUPPLY?

A. WTGGM sells gas to WTGU at its cost, inclusive of all applicable transport and imbalance charges from pipelines upstream of WTGU's systems.

Q. HOW DO YOU ENSURE THAT WTGU GETS COMPETITIVE BIDS AND PRICES FROM BOTH AFFILIATED AND UNAFFILIATED GAS SUPPLIERS?

A. Competitive pricing is assured by obtaining market knowledge. Market knowledge is collected through discussion and negotiation with various suppliers and markets and information obtained from the Intercontinental Exchange, a commodity trading platform posting actual real-time sales and purchases transactions at various points across the United States.

Q. CAN WTGU REDUCE GAS SUPPLY COSTS BY PURCHASING GAS FROM UNAFFILIATED SUPPLIERS?

A. No, WTGU would not reduce supply costs by purchasing from unaffiliated suppliers. WTGGM controls significant gas supplies on the upstream pipelines serving WTGU distribution systems that are well in excess of volumes required by WTGU. These large quantities, controlled by WTGGM, provide WTGU with transportation discounts and imbalance thresholds that would not be available to WTGU if it were to purchase on a stand-alone basis. If WTGU did not purchase from WTGGM, its customers would be paying higher costs for natural gas.

Q. WHAT ARE THE TERMS CONTAINED IN THE GAS SUPPLY AGREEMENTS BETWEEN WTGU AND WTGGM?

A. WTGGM sells gas to WTGU under a standard North American Energy Standards Board agreement. The price paid by WTGU is WTGGM's weighted average cost of gas on the applicable upstream pipeline making deliveries to specific WTGU distribution systems, inclusive of any transportation and imbalance charges.

Q. WHAT ADVANTAGES DO WTGU CUSTOMERS RECEIVE DUE TO WTGU PURCHASING THE MAJORITY OF ITS GAS SUPPLIES FROM AFFILIATE WTGGM?

A. The biggest advantage WTGU and its customers receive results from WTGGM's economies of scale achieved by pairing WTGU supply and transport needs with WTGGM's increased load profile. WTGU also saves labor costs by sharing gas supply personnel between WTGU and WTGGM, and there is reduced credit support required.

Q. DOES WTGGM SELL GAS TO UNAFFILIATED THIRD PARTIES AT THE SAME PRICE IT SELLS GAS TO WTG?

A. No. WTGGM sells gas to WTGU at cost. WTGGM sells gas to unaffiliated third parties at higher prices.

XIV. <u>WINTER STORM URI</u>

A. Overview & Operational Activities

Q. DESCRIBE WINTER STORM URI IN GENERAL TERMS.

A. Winter Storm Uri was a major weather event that occurred in February 2021 and affected all of Texas and large parts of the United States. Governor Greg Abbott issued a Disaster Declaration on February 12, 2021, for all 254 counties in Texas due to severe weather from Winter Storm Uri posing an imminent threat of widespread and extreme property damage, injury and loss of life due to prolonged freezing temperatures, heavy snow and freezing rain statewide.[4] From February

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[4] Proclamation by the Governor of the State of Texas: Governor Abbott Issues Disaster Declaration In Response To Severe Winter Weather In Texas (Feb. 12, 2021) available at https://gov.texas.gov/news/post/governor-abbott-issues-disaster-declaration-in-response-to-severe-winter-weather-in-texas.

13-23, 2021, parts of Texas, including the areas where the Company provides natural gas service, experienced unprecedented cold temperatures that stressed utility systems statewide and drastically increased the demand for natural gas so customers could heat their homes and businesses.

Q. WHAT AREAS OF THE COMPANY'S SYSTEM WERE AFFECTED BY WINTER STORM URI?

A. All parts of WTGU's distribution and transmission systems were subjected to the weather conditions, but they did not suffer negative effects during the Winter Storm as pressures remained strong. The Company did not lose service to any customers.

Q. IS WTGU REQUIRED TO PROVIDE SAFE AND RELIABLE SERVICE TO ITS CUSTOMERS, EVEN UNDER EXTREME WEATHER CONDITIONS?

A. Yes. In addition, on February 12, 2021, the Commission issued an Emergency Order directing gas utilities to prioritize service to human needs customers, even if that meant reducing gas deliveries to non-residential or non-human needs customers.

Q. WHAT STEPS DID WTGU TAKE TO PREPARE ITS SYSTEM FOR WINTER STORM URI?

A. WTGU, as with every winter season, prepares for colder weather well in advance and actively makes sure its system and procedures are prepared for any weather-related issues that may arise.

B. Gas Procurement and Purchases During Winter Storm Uri

Q. DID THE COMPANY UNDERTAKE REASONABLE GAS SUPPLY PLANNING AND PROCUREMENT ACTIVITIES IN ANTICIPATION OF THE 2020/2021 WINTER HEATING SEASON?

A. Yes, which is consistent with the Company's normal annual and monthly gas supply planning activities.

Q. COULD THE COMPANY HAVE PREDICTED WINTER STORM URI AND ITS CONSEQUENCES FOR NATURAL GAS MARKET PRICES?

A. No, Winter Storm Uri was unprecedented. The infrastructure challenges, resulting disruptions in natural gas supply, high natural gas prices, and record demand for natural gas were a surprise to the entire industry.

Q. LEADING UP TO WINTER STORM URI, WHAT GAS PROCUREMENT STEPS DID WTGU TAKE?

A. When the Winter Storm was predicted, WTGU began the process of securing additional natural gas supplies for WTGU's systems and customers.

Q. CAN WTGU CONTROL PRICES FOR NATURAL GAS?

A. No. The price of natural gas is subject to competitive market forces well outside the Company's control. In addition, the Company's gas contracts with suppliers are primarily baseload agreements for monthly supply. Any additional gas that was required was bought at a daily price that during the Winter Storm, escalated to historical highs.

Q. HOW MUCH GAS DID WTGU PURCHASE DURING FEBRUARY 2021 TO PROVIDE SERVICE TO CUSTOMERS?

A. The Company purchased 1,542,313 Mcfs.

Q. HOW DOES THAT COMPARE TO TYPICAL GAS REQUIREMENTS DURING THE SAME TIME OF YEAR IN PRIOR YEARS OR SINCE THEN?

A. Due to the Winter Storm event, the February 2021 purchases were higher than prior February natural gas purchases. For example, in February 2020, WTGU purchased 1,347,589 Mcfs.

Q. COULD WTGU HAVE OBTAINED NATURAL GAS FROM ANY OTHER SOURCES DURING THE STORM?

A. No.

Q. WAS WTGU REQUIRED TO TIMELY PAY NATURAL GAS INVOICES AS THE COMPANY RECEIVED THEM?

A. Yes.

Q. WHAT TYPES OF COSTS ARE INCLUDED IN THE GAS COSTS WTGU INCURRED TO PROVIDE SERVICE DURING WINTER STORM URI?

A. Costs included were typical with most other months, including the commodity price, along with upstream transportation and fuel rates. Also, there is no markup or profit included in any of the Company's gas cost amounts, as WTGU purchases gas from WTGGM.

Q. PLEASE EXPLAIN ANY PENALTIES WTGU WAS CHARGED RELATED TO NATURAL GAS PURCHASES DURING WINTER STORM URI.

A. Any pipeline penalty incurred by WTGU's supplier would have been passed through to WTGU.

Q. DID WTGU CHALLENGE ANY OF THE PENALTIES SUPPLIERS ASSESSED TO THE COMPANY?

A. WTGU's supplier, WTGGM, did challenge some of the penalties that were assessed by pipelines during the Winter Storm. When WTGGM was successful in challenging the penalties, they were not included on the invoice WTGGM sent to WTGU. If WTGGM was not successful in challenging the penalties, the amounts were included on the invoice WTGGM sent to WTGU.

Q. DOES WTGU HAVE DOCUMENTATION TO SUPPORT THE EXTRAORDINARY GAS COSTS IT SEEKS TO RECOVER?

A. Yes. Copies of the invoices the Company received from suppliers are attached to my testimony as Confidential Exhibit JJK-2. In addition, Confidential Exhibit JJK-3 is a copy of the Company's gas supply contract that was in effect during Winter Storm Uri.

Q. WHAT PROCESS DOES WTGU HAVE IN PLACE TO CONFIRM ITS GAS PURCHASES ARE ACCURATE AND REASONABLE?

A. WTGGM's and WTGU's gas supply personnel review invoices for gas supply for accuracy as to pricing and volumes, and those items are approved before being sent to accounting for payment.

Q. WHAT STEPS DID WTGU TAKE TO ENSURE THE GAS COSTS WERE REASONABLE AND NECESSARY?

A. As the Company received invoices, each invoice went through the standard approval process for approving gas cost invoices. The Company has a multi-step approval process during which the Gas Supply Manager and myself as VP of Gas

Marketing reviewed and approved invoices for accuracy and reasonableness. Ms. Edgmon addresses this in more detail in her direct testimony.

Q. ARE ANY AFFILIATE COSTS INCLUDED IN THE COMPANY'S EXTRAORDINARY GAS COSTS?

A. Yes, all of the Company's extraordinary gas costs are affiliate costs because WTGU purchases gas supplies from WTGGM. I addressed this in detail in Section XIII(C) of my testimony, including an explanation of how these amounts comply with the applicable affiliate standard. In addition, the costs were reasonable and necessary because the Company was required to purchase natural gas to ensure customers continued to have service during Winter Storm Uri. In addition, the costs were reasonable because the Company experienced the same high natural gas costs that existed throughout the state during the Winter Storm.

Q. DID THE COMPANY TAKE ON ANY DEBT TO FINANCE THE EXTRAORDINARY GAS COSTS IT EXPERIENCED DURING WINTER STORM URI?

A. No. To avoid delays in procuring natural gas and potential disruptions in service, the Company paid the gas costs "out of pocket" without any debt financing. In addition, there were not any readily available options for the Company to obtain financing, so the Company made the reasonable decision to proceed with paying for the costs itself. This means that WTGU has been carrying these gas costs on its books since February 2021.

C. Extraordinary Gas Cost Recovery

Q. HOW DOES THE COMPANY TYPICALLY RECOVER ITS NATURAL GAS COSTS?

A. The Company recovers its natural gas costs through the terms and conditions of the GCA clause that has been approved by the Commission.

Q. DID THE COMPANY BILL CUSTOMERS AND/OR RECOVER ANY OF ITS FEBRUARY 2021 GAS COSTS THROUGH THE GCA?

A. Yes, the Company billed its jurisdictional customers a total of $906,503.71 in gas costs in February 2021. This amount was determined by taking the total February 2021 billed sales volumes for each gas cost zone (North, West and South) and multiplying it by the purchased gas factor and was in line with gas costs customers were accustomed to being billed as shown in the January, February, and March 2021 customer bills and other documents included in my workpapers.

Q. WAS BILLING CUSTOMERS IN THAT MANNER CONSISTENT WITH THE COMPANY'S GCA?

A. Yes, it was.

Q. HOW DID THE COMPANY DETERMINE THE AMOUNT OF EXTRAORDINARY GAS COSTS INCLUDED IN THE REGULATORY ASSET THE COMPANY SEEKS TO RECOVER IN THIS PROCEEDING?

A. Only extraordinary gas costs were recorded to the regulatory asset. Ordinary or typical gas cost amounts for February 2021 were not included in the asset. Using this approach, WTGU has ensured that only expenses that would not have been incurred but for Winter Storm Uri are included in the regulatory asset. This calculation is set forth in Ms. Edgmon's testimony.

Q. HOW IS THE COMPANY PROPOSING TO RECOVER THE EXTRAORDINARY GAS COSTS IT INCURRED DURING WINTER STORM URI?

A. To avoid a high bill impacts, the Company proposes to recover the total amount over 5 years through a separate charge on customers' bills to allow the Company to easily track charges and cost recovery amounts. A calculation of that amount using adjusted customer volumes for the end of the test year is attached to my testimony as Exhibit JJK-4. In addition, the Company's proposed Winter Storm Rider to recover these costs is included as Exhibit JJK-5.

Q. WHY IS THE COMPANY REQUESTING RECOVERY OF WINTER STORM URI EXTRAORDINARY GAS COSTS AT THIS TIME?

A. The Company has been able to carry these amounts on its books since February 2021 and doing so did not present challenges to the Company's financial situation at the time the costs were incurred or since then. For that reason, it was not necessary for WTGU to participate in the securitization process the Legislature authorized. This rate case is the next opportunity for the Company to request recovery of these costs following a review of their reasonableness and accuracy.

Q. IN ADDITION TO THE GAS COSTS, ARE THERE OTHER AMOUNTS WTGU SEEKS TO RECOVER AS PART OF ITS EXTRAORDINARY GAS COSTS IN THIS CASE?

A. No. Although the Company has been carrying the approximately $3.5 million in extraordinary gas costs on its books since the Winter Storm, the Company is not seeking to recover carrying costs. If the Company were to request carrying costs, they would amount to approximately $1.2 million calculated using the Company's weighted average cost of capital.

XV. PROPOSED TARIFFS

Q. IS WTGU PROPOSING CHANGES TO ITS CURRENT TARIFFS?

A. Yes, Exhibit A to the Statement of Intent is a copy of the proposed tariffs that includes the proposed rates and related terms of service for WTGU.

Q. WHAT ARE THE CHANGES PROPOSED TO WTGU'S TARIFFS?

A. WTGU's current tariffs consist of rates approved by the Commission in Docket No. OS-20-00004347. WTGU proposes the following changes:

- Increasing rates for domestic and non-domestic customers to reflect the Company's higher cost of service;
- Updating the tariff formatting;
- Adding the Winter Storm Cost Recovery Rider to the Company's existing tariffs to recover reasonable and necessary extraordinary gas costs;
- Removing the EDIT Credit Rider because the credits have been fully returned to customers; and
- Making non-substantive changes to the Pipeline Safety Fee Rider.

WTGU does not propose to change the fee, deposit, or general terms of service provisions in the tariffs.

XVI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF TEXAS §
§
COUNTY OF MIDLAND §

AFFIDAVIT OF JACK J. KING

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

1. "My name is Jack J. King. I am over the age of eighteen (18) and fully competent to make this affidavit. The facts stated herein are true and correct based on my personal knowledge. My current position is Vice President of Gas Marketing for West Texas Gas Utility, LLC.
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."

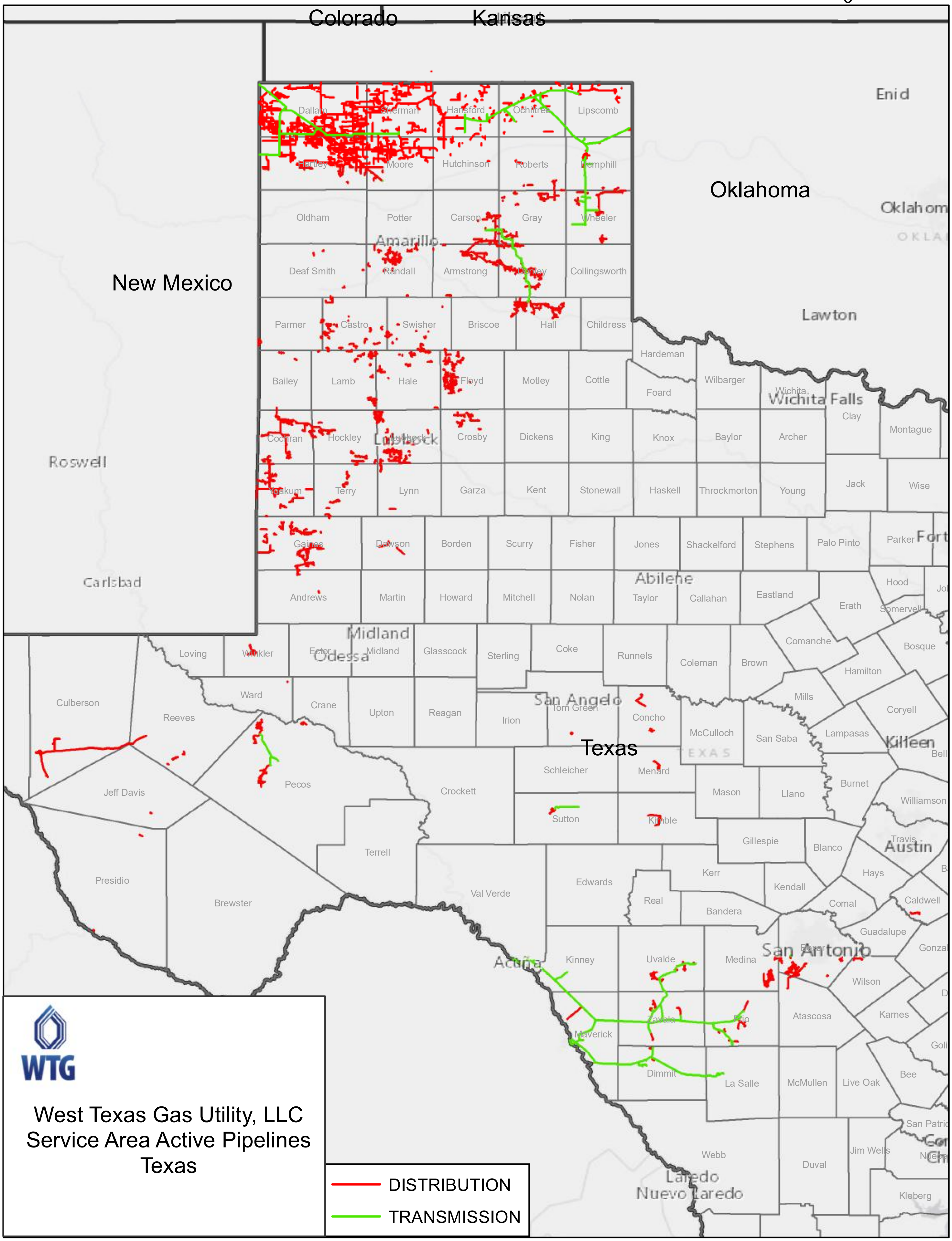
Further affiant sayeth not.

Jack J. King

SUBSCRIBED AND SWORN TO BEFORE ME by the said Jack J. King on this 27th day of June 2024.

Notary Public, State of Texas

JAMIE A. MEAD
Notary Public, State of Texas
Comm. Expires 03-22-2026
Notary ID 133659307


Colorado
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New Mexico
Texas
Enid
Lawton
Roswell
Carlsbad
Amarillo
Lubbock
Wichita Falls
Abilene
Midland
Odessa
San Angelo
Killeen
Austin
San Antonio
Acuña
Laredo
Nuevo Laredo
Dallam
Sherman
Hansford
Ochiltree
Lipscomb
Hartley
Moore
Hutchinson
Roberts
Hemphill
Oldham
Potter
Carson
Gray
Wheeler
Deaf Smith
Randall
Armstrong
Donley
Collingsworth
Parmer
Castro
Swisher
Briscoe
Hall
Childress
Hardeman
Bailey
Lamb
Hale
Floyd
Motley
Cottle
Foard
Wilbarger
Clay
Montague
Cochran
Hockley
Crosby
Dickens
King
Knox
Baylor
Archer
Yoakum
Terry
Lynn
Garza
Kent
Stonewall
Haskell
Throckmorton
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Jack
Wise
Gaines
Dawson
Borden
Scurry
Fisher
Jones
Shackelford
Stephens
Palo Pinto
Parker
Andrews
Martin
Howard
Mitchell
Nolan
Taylor
Callahan
Eastland
Hood
Erath
Somervell
Loving
Winkler
Ector
Glasscock
Sterling
Coke
Runnels
Coleman
Brown
Comanche
Bosque
Hamilton
Ward
Crane
Upton
Reagan
Irion
Tom Green
Concho
McCulloch
San Saba
Mills
Coryell
Lampasas
Bell
Culberson
Reeves
Pecos
Crockett
Schleicher
Menard
Mason
Llano
Burnet
Williamson
Jeff Davis
Sutton
Kimble
Gillespie
Blanco
Travis
Terrell
Presidio
Brewster
Val Verde
Edwards
Kerr
Kendall
Hays
Real
Bandera
Comal
Caldwell
Guadalupe
Kinney
Uvalde
Medina
Bexar
Wilson
Zavala
Frio
Atascosa
Karnes
Maverick
Dimmit
La Salle
McMullen
Live Oak
Bee
Webb
Duval
Jim Wells
Kleberg
West Texas Gas Utility, LLC
Service Area Active Pipelines
Texas
DISTRIBUTION
TRANSMISSION

Exhibit JJK-2 is Confidential
and will be provided pursuant to the terms of the
Protective Agreement

Exhibit JJK-3 is Confidential
and will be provided pursuant to the terms of the
Protective Agreement

Winter Storm Surcharge Calculation

Total Extraordinary Gas Costs	$ 3,502,862.41
Non-Domestic Volumes (Sch A)	634,364
Domestic Volumes (Sch A)	1,063,235
Total Volumes (Mcf)	1,697,599
Reovery Period in Years	5
Total Recovery Period Annualized Mcf	8,487,995
Winter Storm Surcharge per Mcf	$ 0.41

Effective:____________

WINTER STORM URI SURCHARGE

APPLICABILITY

All jurisdictional customers in the unincorporated or environs areas of West Texas Gas Utility, LLC ("WTGU") Service Area.

PURPOSE

The purpose of the Winter Storm Uri Surcharge is to authorize WTGU to recover the reasonable, necessary, and prudent extraordinary gas costs incurred by WTGU as a result of Winter Storm Uri. The rate schedule is authorized by the Railroad Commission of Texas's ("Commission") Final Order in Case No. OS-24-00017816, which approved a Winter Storm Uri Regulatory Asset and the recovery of the costs contained in the regulatory asset through a monthly surcharge. WTGU is authorized and directed to assess the Winter Storm Uri Surcharge rate as set forth in the section below.

SURCHARGE RATE

All Mcf during each billing period: $0.41 per Mcf.

This rate will be in effect until all approved and expended Winter Storm Uri costs, up to $3,502,862.41 ("Regulatory Asset Amount"), are recovered under the applicable rate schedules. Any excess recovery of the Regulatory Asset Amount shall be calculated and refunded to customers through a final true-up under this rate schedule.

OTHER ADJUSTMENTS

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

CONDITIONS

1. Subject to all applicable laws and orders, and WTGU's rules and regulations on file with the regulatory authority.
2. Uncollectible amounts, actually written off, associated with this surcharge shall be added back to the balance to be recovered via this surcharge.
3. Any amounts that were included in the Regulatory Asset Amount that are refunded to WTGU subsequent to the Final Order in Case No. OS-24-00017816 shall be subtracted from the balance and shall not be recovered via this surcharge.

WINTER STORM URI SURCHARGE RECOVERY COMPLIANCE REPORT

WTGU shall file a reconciliation report annually on or before March 31, commencing in 2026 and ceasing after a reconciliation report is filed at the end of the month following the month in which the Regulatory Asset Amount is fully recovered via the final reconciliation true-up (if applicable). WTGU shall file the report with the Commission, addressed to the Director of the Oversight and Safety Division and referencing Case No. OS-24-00017816, Winter Storm Uri Surcharge Recovery Report. The report shall include:

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

Reports for the Commission should be filed electronically at GUD_Compliance@rrc.texas.gov or at the following address:

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

WINTER STORM URI SURCHARGE

APPLICABILITY

All Jurisdictional customers in the incorporated areas or cities in West Texas Gas Utility, LLC's ("WTGU") Texas Service Area.

PURPOSE

The purpose of the Winter Storm Uri Surcharge is to authorize WTGU to recover the reasonable, necessary, and prudent extraordinary gas costs incurred by WTGU as a result of Winter Storm Uri. The rate schedule is authorized by the Railroad Commission of Texas's ("Commission") Final Order in Case No. OS-24-00017816 and by cities that approved the corresponding request WTGU made with incorporated regulatory authorities, which approved a Winter Storm Uri Regulatory Asset and the recovery of the costs contained in the regulatory asset through a monthly surcharge. WTGU is authorized and directed to assess the Winter Storm Uri Surcharge rate as set forth in the section below.

SURCHARGE RATE

All Mcf during each billing period: $0.41 per Mcf.

This rate will be in effect until all approved and expended Winter Storm Uri costs, up to $3,502,862.41 ("Regulatory Asset Amount"), are recovered under the applicable rate schedules. Any excess recovery of the Regulatory Asset Amount shall be calculated and refunded to customers through a final true-up under this rate schedule.

OTHER ADJUSTMENTS

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

CONDITIONS

1. Subject to all applicable laws and orders, and WTGU's rules and regulations on file with the regulatory authority.
2. Uncollectible amounts, actually written off, associated with this surcharge shall be added back to the balance to be recovered via this surcharge.

3. Any amounts that were included in the Regulatory Asset Amount that are refunded to WTGU subsequent to the Final Order in Case No. OS-24-00017816 shall be subtracted from the balance and shall not be recovered via this surcharge.

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

WTGU shall file a reconciliation report annually on or before March 31, commencing in 2026 and ceasing after a reconciliation report is filed at the end of the month following the month in which the Regulatory Asset Amount is fully recovered via the final reconciliation true-up (if applicable). WTGU shall file the report with the Commission, addressed to the Director of the Oversight and Safety Division and referencing Case No. OS-24-00017816, Winter Storm Uri Surcharge Recovery Report. The report shall include:

- The volumes used by month by customer class during the applicable period;
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Compliance Filing
Director of Oversight and Safety Division
Gas Services Dept.
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

WORKPAPERS

TO

DIRECT TESTIMONY

OF

JACK J. KING

Workpapers to the Direct Testimony of Jack J. King are voluminous and are being provided in electronic format.

CASE NO. 00017816

STATEMENT OF INTENT OF	**§**	**BEFORE THE**
WEST TEXAS GAS UTILITY, LLC TO	**§**	
INCREASE GAS UTILITY RATES	**§**	**RAILROAD COMMISSION**
WITHIN THE UNINCORPORATED	**§**	
AREAS OF TEXAS	**§**	**OF TEXAS**

DIRECT TESTIMONY

OF

AMANDA EDGMON

ON BEHALF OF

WEST TEXAS GAS UTILITY, LLC

July 16, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF AMANDA EDGMON

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Amanda Edgmon. My business address is 303 Veterans Airpark Lane, Suite 5000, Midland, Texas 79705.

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

A. I am employed by West Texas Gas Utility, LLC ("WTGU" or the "Company") as the Treasurer and Secretary. I am also the Regulatory Accountant for WTGU.

Q. WHAT ARE YOUR DUTIES AS THE TREASURER, SECRETARY AND REGULATORY ACCOUNTANT?

A. As the Treasurer, I supervise the Company's cash management ensuring sufficient funds are available to meet ongoing operational requirements. As the Secretary, I execute and maintain all required corporate filings, documents, reports, and records according to applicable laws and regulations. My Regulatory Accountant duties include making all the accounting filings with the Railroad Commission of Texas ("Commission"), the Oklahoma Corporation Commission and the Federal Energy Regulatory Commission ("FERC") on behalf of WTGU.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated from Texas Tech University in 2009 with a bachelor's degree in Business Administration, majoring in Finance. I began my employment with WTGU's predecessor entity, West Texas Gas, Inc., upon graduation in May 2009 as a staff accountant. I became the Regulatory Accountant in 2013. In 2020, I was elected as the Secretary and Treasurer of WTGU.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I filed testimony with the Commission in Docket No. OS-20-00004347.

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 exhibits listed in the table of contents.

Q. ARE YOU SPONSORING OR CO-SPONSORING ANY SCHEDULES?

A. Yes. I am co-sponsoring or sponsoring the following schedules:

B-1 Operations and Maintenance Expense

B-2 Administrative and General Expenses

C-5 Gas Reliability Infrastructure Program Additions

H-1 Payroll Summary

H-2 Payroll Analysis

H-3 Bad Debts

H-4 Advertising Expenses

H-5 Donation and Contributions

H-6 Lobbying Expenses

H-7 Penalties and Fine

H-8 Outside Services charged to A&G Accounts

H-9 Legal Expense Detail

H-10 Lost and Unaccounted for Gas
I-1 Organizational Chart
I-2 Charges by Affiliates to WTGU
I-3 Charges by Affiliates to Others

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 addresses the Company's books and records, confirms that the Company has followed the Commission's rules when preparing and presenting its filing package, presents plant investment records that are subject to a prudence review in this case, presents the test-year, supports the recovery of WTG Downstream Services, LLC ("WTGDS") costs, and supports recovery of the Company's extraordinary gas costs from Winter Storm Uri. Company witnesses Jack J. King and Matthew S. Smith support the reasonableness and necessity of operations and maintenance ("O&M") expenses, administrative and general ("A&G") expenses and capital investment presented in the filing, and Mr. King also addresses Winter Storm Uri extraordinary gas costs. Additionally, Company witness Dr. Bruce Fairchild supports the Company's overall cost of service, requested return and cost of debt, and sponsors the majority of WTGU's rate filing package schedules.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to attest to the accuracy of the Company's books and records that were used to develop the rate study performed by Dr. Fairchild, support the recovery of WTGDS costs and provide any supporting documentation or information concerning the Company's financial records. I also address issues related to the allocation factor that applies to jurisdictional customers, which WTGU is seeking to change in this proceeding to better align the recovery of costs from customers who benefit from the investment the Company makes. Finally, I discuss the accounting aspects of the Company's request to recover extraordinary gas costs incurred to provide service to customers during Winter Storm Uri.

III. BOOKS AND RECORDS

Q. WOULD YOU BRIEFLY DESCRIBE THE METHOD BY WHICH WTGU'S BOOKS AND RECORDS ARE MAINTAINED AND NOTE ANY SIGNIFICANT CHANGES IN THOSE METHODS SINCE THE COMPANY'S LAST RATE CASE?

A. The books and records are maintained in accordance with Generally Accepted Accounting Principles ("GAAP") and presented pursuant to the Uniform System of Accounts ("USOA"), as prescribed by FERC, and the Commission. I have attached a cross reference to this testimony (Exhibit AE-1), which shows the corresponding FERC account number to WTGU's general ledger chart of accounts. Except for revised depreciation rates pursuant to the Commission's final order, there have been no significant changes in the methods by which the Company keeps its books and records since WTGU presented its last full rate case in Docket No. OS-20-00004347.

Q. IN THE PROCESS OF PROVIDING TEST PERIOD DATA TO DR. FAIRCHILD, DID YOU DISCOVER ITEMS IN THE COMPANY'S BOOKS AND RECORDS THAT YOU NEEDED TO CORRECT?

A. No, I did not.

Q. ARE WTGU'S REVENUES AND EXPENSES FOR THE TEST YEAR, AS SHOWN ON THE BOOKS AND RECORDS OF THE COMPANY, TRUE AND CORRECT TO THE BEST OF YOUR KNOWLEDGE?

A. Yes.

Q. PLEASE SUMMARIZE HOW THE BOOKS AND RECORDS OF WTGU ARE MAINTAINED AND UTILIZED IN THE REGULAR COURSE OF BUSINESS.

A. WTGU maintains its books and records in accordance with GAAP. They are presented pursuant to the USOA. The USOA is the prescribed methodology for maintaining records in all of the state jurisdictions that regulate WTGU's natural gas distribution operations. These regulations are found and defined in the Code of Federal Regulations, Title 18 – Conservation of Power and Water Resources, Subchapter F – Accounts, Natural Gas Accounts, Part 201 – Uniform System of Accounts. Commission Rule § 7.310 requires that the Company keep its books in accordance with the FERC USOA. To demonstrate this compliance, the corresponding FERC accounts are included in the required schedules in this filing. WTGU's accounting procedures utilize integrated computerized business systems to efficiently process, record and maintain transactions generated in the regular course of business. Financial transactions are created and entered into the system at or near the time of the transactions by personnel having personal knowledge of the transactions, as well as of the applicable accounting procedure requirements.

Q. AS A REGULATORY ACCOUNTANT, HOW DO YOU ASSURE YOURSELF THAT TRANSACTIONS ARE RECORDED PROPERLY?

A. As the Company's regulatory accountant, I have personal knowledge of the Company's business processes, accounting systems, and integrity of its financial reporting. The organization is staffed with qualified accounting personnel. WTGU has established and maintained controls that ensure the accuracy of its books and records. These controls help identify any necessary adjustments to accounting entries, which are then recorded to the original books and records. Additionally, WTGU engages the Whitley Penn LLP CPA accounting firm to perform an annual audit of the Company's books to help ensure the continued integrity of WTGU's financial reporting to customers, vendors, regulatory authorities, and others.

Q. ARE THE COSTS RECORDED ON WTGU'S BOOKS AND RECORDS SUPPORTED BY UNDERLYING INVOICES OR OTHER RECORDS?

A. Yes. In order for a cost to be recorded in WTGU's general ledger, there must be a vendor invoice, or other underlying documentation, that has been properly approved or authorized, to support the entries recorded on WTGU's books. Examples of other documentation include timesheets, contracts, leases, or other agreements.

Q. ARE WTGU'S BOOKS AND RECORDS MAINTAINED IN A MANNER BY WHICH REVENUES, EXPENSES AND CAPITAL INVESTMENTS OF THE VARIOUS LOCATIONS CAN BE IDENTIFIED?

A. Yes, WTGU's books and records are generally maintained for each field (district) office in order to identify revenues, expenses, and capital expenditures by location. To accomplish this, WTGU has set up a unique entity ID number for each district location.

Q. DURING THE TEST YEAR, DID THE COMPANY HAVE IN PLACE ANY PROCESS OR SYSTEM FOR THE REVIEW AND VALIDATION OF INVOICES?

A. All invoices for WTGU are scanned and processed through our Docuphase software. Invoices are either sent to our Post Office Box, e-mailed to our accounts payable e-mail address, or scanned by an accounts payable clerk in this office. Once scanned, an electronic copy of the invoice is dispatched to a district manager for approval. Invoices over certain amounts require approval from senior employees or management with increasing levels of responsibility. After the invoice is approved, the district clerk or the accountant codes the invoice. The accountant is then responsible for reviewing the invoice to ensure it is properly coded before payment is made.

Q. PLEASE DESCRIBE THE PROCESS USED TO TEST INTERNAL CONTROLS.

A. Internal controls are reviewed annually for effectiveness by WTGU's independent auditors. Upon the completion of the audit, the auditors provide WTGU with an "audit wrap up" report that identifies any weaknesses in internal controls and makes specific recommendations to management for solutions, if needed.

Q. CAN YOU SUMMARIZE THE PROCESS USED BY WHITLEY PENN LLP CPA TO PERFORM ITS AUDIT FUNCTION?

A. Whitley Penn LLP CPA auditors utilize generally accepted auditing standards to perform the annual audit of WTGU's books and records. These auditing standards establish a level of protocol the auditors must recognize during the performance of their field work and the reporting of their finished work. The auditing standards used by Whitley Penn LLP CPA are as follows:

A. Standards of Field Work

1. The auditor must adequately plan the work and must properly supervise any assistants.
2. The auditor must obtain a sufficient understanding of the entity and its environment, including its internal control, to assess the risk of material misstatement of the financial statements whether due to error or fraud, and to design the nature, timing, and extent of further audit procedures.
3. The auditor must obtain sufficient appropriate audit evidence by performing audit procedures to afford a reasonable basis for an opinion regarding the financial statements under audit.

B. Standards of Reporting

1. The auditor must state in the auditor's report whether the financial statements are presented in accordance with generally accepted accounting principles.

2. The auditor must identify in the auditor's report those circumstances in which such principles have not been consistently observed in the current period in relation to the preceding period.

3. When the auditor determines that informative disclosures are not reasonably adequate, the auditor must so state in the auditor's report.

4. The auditor must either express an opinion regarding the financial statements, taken as a whole, or state that an opinion cannot be expressed, in the auditor's report. When the auditor cannot express an overall opinion, the auditor should state the reasons therefore in the auditor's report. In all cases where an auditor's name is associated with financial statements, the auditor should clearly indicate the character of the auditor's work, if any, and the degree of responsibility the auditor is taking, in the auditor's report.

Q. HOW DOES THE ACCOUNTING SYSTEM ALLOW FOR THE SEPARATE RECORDING AND TRACKING OF COSTS FOR WTGU'S UTILITY DISTRICTS?

A. WTGU's accounting books and records are maintained separately and apart from its subsidiaries. Within this accounting system, revenues and expenses must be identified to a specific individual profit center (i.e., WTGU's home office or district office). This identification process allows WTGU to create accounting reports for each profit center.

Q. WERE THE BOOKS AND RECORDS OF THE COMPANY PROVIDED TO COMPANY WITNESSES FOR UTILIZATION IN THEIR ANALYSIS FOR RATEMAKING PURPOSES?

A. Yes.

Q. DO THE AMOUNTS SHOWN IN THE RATE MODEL THAT ARE IDENTIFIED AS "PER BOOKS" ACCURATELY REFLECT THE COMPANY'S BOOKS?

A. Yes.

Q. WHAT STEPS DID WTGU TAKE TO ASSURE CONSISTENCY BETWEEN THE COMPANY'S BOOKS AND RECORDS AND THE RATE MODEL?

A. Upon completion of the rate model, all schedules containing "Per Book" balances were compared directly to WTGU's Balance Sheet on December 31, 2023 and WTGU's Income Statement for the twelve-month test period ending December 31, 2023. Any differences between the rate model and WTGU's trial balance were discussed with the consultants for correction or reference, as applicable.

Q. PLEASE DESCRIBE SCHEDULES THAT YOU SPONSOR OR CO-SPONSOR.

A. I co-sponsor Schedule B-1 (Operations and Maintenance Expense) with Messrs. Smith, Fairchild and King and co-sponsor Schedule B-2 (Administrative and General Expenses) with Messrs. Fairchild and King. Schedule B-1 presents WTGU's O&M expense by month for the test-year inclusive of adjustments. Schedule B-2 presents WTGU's A&G expense for the test-year inclusive of adjustments. I co-sponsor Schedule C-5 (Gas Reliability Infrastructure Program Additions) with Mr. Smith. Schedule C-5 presents all of the investment and capital projects subject to a prudence review in this proceeding. I co-sponsor schedules H-1 (Payroll Summary), H-2 (Payroll Analysis), H-3 (Bad Debts), H-4 (Advertising Expenses), H-5 (Donations and Contributions), H-6 (Lobbying Expenses), H-7 (Penalties and Fines), H-8 (Outside Services Charged to A&G Accounts), H-9 (Legal Expense Detail), H-10 (Lost and Unaccounted for Gas), I-1 (Organizational Chart), I-2 (Charges by Affiliates to WTGU), and I-3 (Charges by Affiliates to Others) with Mr. King. Schedules H-1 through I-3 present various aspects of the Company's test-year cost of service, confirm that the Company made adjustments to the filing to comply with Commission rules, and support affiliate expenses included in the filing.

IV. <u>COMPLIANCE WITH COMMISSION RULES AND NOTICES</u>

Q. PLEASE DISCUSS THE SYSTEM OF ACCOUNTS THAT THE COMPANY UTILIZES.

A. WTGU has set up a cross reference of its general ledger chart of accounts with the USOA. For regulatory reporting purposes, general ledger balances are entered into an excel spreadsheet, which includes both sets of account numbers. This allows WTGU to do regulatory reporting as needed using the USOA and still tie balances back to its general ledger.

Q DO THE BOOKS AND RECORDS, AS WELL AS THE SUMMARIES AND EXCERPTS THEREFROM, QUALIFY FOR THE PRESUMPTION SET FORTH IN THE COMMISSION'S RULE § 7.503?

A. Yes. Because the Company maintains its books and records in accordance with

Commission Rule § 7.310, the amounts referenced on its books and records, as well as summaries and excerpts from those books and records, are presumed to be reasonable and necessary under the provisions of Rule § 7.503.

Q. HAS THE COMPANY COMPLIED WITH THE COMMISSION'S OTHER RULES THAT RELATE TO COST OF SERVICE FILINGS IN PRESENTING ITS REQUEST IN THIS CASE?

A. Yes. The Company has complied with all of the Commission's rules related to cost of service filings. For instance, Commission Rule § 7.501 requires a gas utility in a rate proceeding to present evidence related to certain types of costs and transactions. These costs include lobbying and legislative advocacy expenses, business gifts, entertainment, charitable or civic contributions, and certain advertising expenses. Consistent with Commission Rule § 7.501, these items have been identified and excluded from the filing pursuant to Commission Rule § 7.5414.

Commission Rule § 7.5252 also requires a gas utility in a rate proceeding to book depreciation and amortization on a straight-line basis over the useful life expectancy of the property or facility in question. Items of plant, revenues, expenses, taxes, or reserves that are shared or common to the service area are to be allocated to apportion them fairly and justly among the divisions of the utility. Company witness Dane Watson addresses WTGU's requested depreciation and amortization treatment. Additionally, Commission Rule § 7.5252 requires the exclusion of nonutility amounts from the Company's cost of service.

Commission Rule § 7.5414 states that actual expenditures for advertising will be allowed as a cost of service item for ratemaking purposes provided that the total sum of such expenditures does not exceed one-half of 1% of the gross receipts of the utility for utility services rendered to the public. Consistent with this requirement, the Company has included only $21,153 in the requested cost of service for advertising during the test year. This amount is 0.0153% of the gross receipts of the utility for utility services rendered to the public.

Q. DOES RULE § 7.5414 PROHIBIT CERTAIN EXPENDITURES FROM BEING INCLUDED IN THE COST OF SERVICE?

A. Yes. Commission Rule § 7.5414 states that no expenditures shall be allowed as a cost of service for ratemaking purposes if spent for the purpose of influencing public opinion with respect to legislative, administrative, or electoral matters, or with respect to any controversial issue of public importance. Additionally, Commission Rule § 7.5414 excludes from the cost of service funds expended in support of, or membership in, social, recreational, fraternal, or religious clubs or organizations, and funds expended for contributions and donations to charitable, religious, or other nonprofit organizations or institutions.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS IN ACCORDANCE WITH COMMISSION RULE § 7.5414?

A. Yes. The Company decreased its test year expense by $10,219 for expenses related to legislative activities as shown on Schedule B-2.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO TEST YEAR EXPENSES RELATED TO MEALS, ENTERTAINMENT, LODGING, AND TRAVEL EXPENSES?

A. Yes. The Company is not seeking recovery of expenses related to meals, entertainment, hotels, or travel expenses. The adjustment related to this reduction to test year expense is shown on Schedule B-2.

Q. HAS THE COMPANY INCLUDED ANY PROHIBITED EXPENDITURES IN ITS COST OF SERVICE?

A. No.

Q. ARE YOU FAMILIAR WITH THE REQUIREMENTS OF COMMISSION RULE § 7.5530?

A. Yes. Commission Rule § 7.5530 states that in any rate proceeding, any utility and/or municipality claiming reimbursement for its rate case expenses pursuant to Gas Utility Regulatory Act ("GURA") § 103.022, shall have the burden to prove the reasonableness of such rate case expenses by a preponderance of the evidence. Consistent with Rule § 7.5530, the Company will provide support for all reasonable rate case expenses requested for reimbursement when such expenses are known.

Q. ARE WTGU'S BOOKS AND RECORDS AVAILABLE FOR REVIEW?

A. Yes. The Company's books and records are available to a party for review at the Company's offices in Midland, Texas. Confidential information will be made available to those qualified individuals who have executed a confidentiality agreement.

Q. ARE THERE ANY COMMISSION NOTICES WTGU HAS COMPLIED WITH THAT RESULT IN COSTS IT SEEKS TO RECOVER IN THIS CASE?

A. Yes. The Company complied with the Notice of Authorization for Regulatory Asset Accounting for Local Distribution Companies Affected by the February 2021 Winter Weather Event issued in February 2021 ("Uri Notice"). I address Winter Storm Uri costs recorded to a regulatory asset in more detail below.

V. TEST YEAR, PRUDENCE OF CAPITAL SPEND AND COMPLIANCE WITH COMMISSION ORDERS

Q. WHAT IS THE TEST YEAR IN THIS CASE?

A. The test year in this case is January 1, 2023 through December 31, 2023.

Q. IS THE COMPANY SEEKING ANY PRUDENCE DETERMINATIONS RELATED TO PLANT IN SERVICE?

A. Yes, the Company is seeking a prudence determination for all capital investment made in the WTGU system since rates were last approved in Docket No. OS-20-00004347 through December 31, 2023. Attached to my testimony as Exhibit AE-3 are the capital expense reports included in each of the Company Gas Reliability Infrastructure Program ("GRIP") filings since Docket No. OS-20-00004347. The exhibit includes the capital expense reports the Company provided with the GRIP filing it made on May 17, 2024, which addresses projects placed in service during the test year, January 1, 2023 through December 31, 2023. As the preparer of the Company's annual GRIP filings, I sponsor the reports, while Mr. King and Mr. Smith support the reasonableness, necessity, and prudence of the investment.

Q. IS THE COMPANY REQUESTING RECOVERY OF ANY PLANT INVESTMENT MADE AFTER THE END OF THE TEST YEAR?

A. No, the filing does not include any known and measurable adjustments for post-test year plant.

Q. HAS THE COMPANY BEEN REQUIRED TO COMPLY WITH ANY COMMISSION ACCOUNTING ORDERS SINCE ITS LAST RATE CASE?

A. Yes. The Company was ordered in GUD No. 10695 to account for the impact of the Tax Cuts and Jobs Act of 2017. In accordance with the Commission's accounting order in that docket, the Company made a filing under § 104.111 of GURA that was docketed as GUD No. 10763 and continued to account for Excess Deferred Income Tax ("EDIT") amounts. In the Company's last rate case, Docket No. OS-20-00004347, the Commission ordered a one-time EDIT refund and that the Company to continue to amortize the remaining EDIT liability through 2045 in compliance with GUD No. 10695 and guidance from the Internal Revenue Service.[1] The Company completed the one-time EDIT refund and confirmed the refund through a compliance filing made on June 16, 2021 in Docket No. OS-20-00004347. The company also continues to amortize the remaining EDIT liability. In this proceeding, Dr. Fairchild addresses the treatment of EDIT amounts.

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[1] *Statement of Intent of West Texas Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of Texas*, Docket No. OS-20-00004347 consol., Final Order at Finding of Fact ("FoF") Nos. 41-45 (Feb. 9, 2021).

VI. JURISDICTIONAL FACTOR FOR GRIP FILINGS

Q. WHO ARE THE COMPANY'S JURISDICTIONAL CUSTOMERS?

A. "Jurisdictional" is the term that the Company uses to refer to customers whose rates are regulated under the Commission's jurisdiction. These customers include residential, commercial, public authority, and non-profit.

Q. WHO ARE THE COMPANY'S NON-JURISDICTIONAL CUSTOMERS?

A. The Company also serves customers whose rates are not under the jurisdiction of the Commission. The customers include commercial, irrigation, and transport customers who use gas for agricultural use.

Q. WHAT JURISDICTIONAL FACTOR HAS WTGU BEEN USING IN GRIP FILINGS?

A. As required by the Commission's final order in the last rate case, the Company has applied a 36.75% allocation to jurisdictional customers, which the parties agreed would be analyzed further in the Company's next rate case.[2] The rationale for the jurisdictional factor is that the jurisdictional customers should not pay for portions of the Company's gas system that are used to serve non-jurisdictional customers. However, in practice, the jurisdictional factor has prevented the company from fully recovering costs for portions of the gas system that are used exclusively or primarily to serve jurisdictional customers.

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[2] *Id.* at FoF No. 37.

Q. IS WTGU PROPOSING TO CHANGE THE JURISDICTIONAL FACTOR IN THIS CASE?

A. Yes. The percentage was originally based on the results of the Class Cost of Service Study ("CCOSS") in prior rate cases. In the last rate case, the results of the CCOSS indicated that 37.84% of investment should be allocated to jurisdictional customers.[3] The Company agreed at the time to use the 36.75% allocator in future GRIP filings, with the caveat that the issue would be analyzed in the next rate case. Thus, since the last rate case, the Company has been only recovering 36.75% of its capital investment through GRIP even if that capital investment was made for the sole benefit and service of jurisdictional customers.

In this case, WTGU proposes that 100% of capital investment and costs that benefit only jurisdictional customers be recovered from jurisdictional customers. By the same token, WTGU proposes that capital investment and costs that benefit only non-jurisdictional should not be recovered from jurisdictional customers. For investment that benefits both jurisdictional and non-jurisdictional customers, WTGU proposes to recover those costs based on the results of Dr. Fairchild's class cost of service study in this proceeding. The results of that study demonstrate that 51.22% of those joint costs should be recovered from jurisdictional customers. Accordingly, WTGU proposes that a 51.22% jurisdictional allocation factor should be approved for use in future GRIP filings. Mr. Smith addresses examples of the Company's capital investment that fall in these categories in more detail in his

[3] Docket No. OS-20-00004347, SOI Ex. G, Cost of Service Schedules at Tab "J COSS".

direct testimony. Dr. Fairchild explains in detail his class cost of service study and the resulting jurisdictional allocation factor.

Q. PLEASE EXPLAIN HOW THE FACTOR IS APPLIED IN THE COMPANY'S RECENT GRIP FILINGS.

A. I rely on the schedules in the Commission's Interim Rate Adjustment Application and have done so for several years. The jurisdictional factor is applied to the total Interim Rate Adjustment Amount that is calculated using the GRIP formula and appears on Schedule IRA-5, IRA Summary at Line No. 26:

West Texas Gas Utility, LLC
Interim Rate Adjustment Application
12 Month Period Ending December 31, 2023
Interim Rate Adjustment Summary

Line No.	Description	As of 12/31/2022	Adjustments	Ref	As of 12/31/2023	Change in Investment
(a)	(b)	(c)	(d)	(e)	(f)	(g)
						= (f) - (c) + (d)
11	Direct Utility Plant Investment	$ 229,409,521	$ -		$ 243,939,609	$ 14,530,088
12	Direct Accumulated Depreciation	68,844,665	-		74,140,293	5,295,627
13	Allocated Utility Plant Investment (If applicable)	477,117	-		434,623	(42,494)
14	Allocated Accumulated Depreciation (If applicable)	56,386	-		112,943	56,558
15	Miscellaneous Adjustments	(9,002,214)	-		(9,868,938)	(866,724)
16	Net Utility Plant Investment (Ln 11 - 12 + 13 - 14 + 15)	$ 151,983,372	$ -		$ 160,252,058	$ 8,268,686
17						
18	Calculation of the Interim Rate Adjustment Amount - Texas Operations:					
19	Rate of Return					7.32%
20	Return					$ 605,169
21	Depreciation Expense					299,620
22	Property-related Taxes (Ad Valorem)					131,060
23	Revenue-related Taxes and State Margin Tax					-
24	Federal Income Tax					123,198
25	Interim Rate Adjustment Amount (Sum of Ln 19 through Ln 24)					$ 1,159,047
26	Percentage Jurisdictional (Per OS-20-00004347)					36.75%
27						
28	Interim Rate Adjustment Jurisdictional Amount (Ln 25 times Ln 26)					$ 425,950
29						

Q. WHAT ARE THE CONSEQUENCES OF APPLYING THE JURISDICTIONAL FACTOR IN THAT WAY?

A. The 36.75% factor inaccurately reduces the Company's recovery of capital investment that benefits only jurisdictional customers. Schedule IRA-12, Direct Additions Report, contains the list of projects included in the Company's GRIP filing. One of the requirements in that schedule is to identify the Customer Class Benefited in Column H. For the projects classified as "Jurisdictional," the

Company is able to confirm that the project benefits and the costs are caused by only jurisdictional customers. Yet, in Schedule IRA-5, where the overall incremental investment is calculated, the 36.75% jurisdictional factor is applied to all projects, including projects classified as Jurisdictional. The result is that the Company is not able to fully recover the cost of jurisdictional-only investment from jurisdictional customers through the statutory GRIP process.

Q. CAN YOU ILLUSTRATE THIS WITH A RECENT WTGU GRIP FILING?

A. Yes. Below is an excerpt from Schedule IRA-12, Direct Additions Report, that identifies many Distribution Integrity Management Program ("DIMP") projects the Company completed in 2023 that benefited only jurisdictional customers.

50	1660268	DIMP	PO 90318 2023 DIMP KERMIT	376.0	12/31/23	KERMIT & ENVIRIONS	Jurisdictional	1,111,088.84	TX	100.00%	1,111,088.84
51	1660269	DIMP	PO 90321 2023 DIMP VAN	376.0	12/31/23	VAN HORN & ENVIRONS	Jurisdictional	306,976.74	TX	100.00%	306,976.74
52	1660270	DIMP	PO 90322 2023 DIMP	376.0	12/31/23	TRANS PECOS AREA - RURAL	Jurisdictional	167,720.29	TX	100.00%	167,720.29
53	1660271	DIMP	PO 90325 2023 DIMP	376.0	12/31/23	JUNCTION & ENVIRONS	Jurisdictional	23,729.29	TX	100.00%	23,729.29
54	1660272	DIMP	PO 90326 2023 DIMP MENARD	376.0	12/31/23	MENARD & ENVIRONS	Jurisdictional	263,932.01	TX	100.00%	263,932.01
55	1660273	DIMP	PO 90327 2023 DIMP SONORA	376.0	12/31/23	SONORA & ENVIRONS	Jurisdictional	489,867.95	TX	100.00%	489,867.95
56	1660274	DIMP	PO 90328 2023 DIMP EDEN	376.0	12/31/23	EDEN & ENVIRONS	Jurisdictional	597,780.73	TX	100.00%	597,780.73
57	1660275	DIMP	PO 90329 2023 DIMP	376.0	12/31/23	CHRISTOVAL ENVIRONS	Jurisdictional	3,376.69	TX	100.00%	3,376.69
58	1660276	DIMP	PO 90332 2023 DIMP	376.0	12/31/23	CANADIAN & ENVIRONS	Jurisdictional	1,099,462.73	TX	100.00%	1,099,462.73
59	1660277	DIMP	PO 90333 2023 DIMP	376.0	12/31/23	WHEELER TX & ENVIRONS	Jurisdictional	742,078.17	TX	100.00%	742,078.17
60	1660278	DIMP	PO 90334 2023 DIMP	376.0	12/31/23	SHAMROCK & ENVIRONS	Jurisdictional	734,159.58	TX	100.00%	734,159.58
61	1660279	DIMP	PO 90335 2023 DIMP	376.0	12/31/23	HIGGINS & ENVIRONS	Jurisdictional	6,562.38	TX	100.00%	6,562.38
62	1660280	DIMP	PO 90336 2023 DIMP	376.0	12/31/23	DARROUZETT & ENVIRONS	Jurisdictional	6,299.88	TX	100.00%	6,299.88
63	1660281	DIMP	PO 90337 2023 DIMP	376.0	12/31/23	FOLLETT & ENVIRONS	Jurisdictional	448,219.71	TX	100.00%	448,219.71
64	1660282	DIMP	PO 90338 2023 DIMP MIAMI	376.0	12/31/23	MIAMI & ENVIRONS	Jurisdictional	72,438.11	TX	100.00%	72,438.11
65	1660283	DIMP	PO 90340 2023 DIMP	376.0	12/31/23	CANADIAN AREA TX - RURAL	Jurisdictional	49,773.52	TX	100.00%	49,773.52
66	1660284	DIMP	PO 90349 2023 DIMP	376.0	12/31/23	TEXLINE & ENVIRONS	Jurisdictional	26,747.06	TX	100.00%	26,747.06
67	1660288	DIMP	PO 90357 2023 DIMP	376.0	12/31/23	SOMERSET & ENVIRONS	Jurisdictional	1,441,222.97	TX	100.00%	1,441,222.97
68	1660289	DIMP	PO 90358 2023 DIMP DEVINE	376.0	12/31/23	DEVINE & ENVIRONS	Jurisdictional	8,923.34	TX	100.00%	8,923.34
69	1660290	DIMP	PO 90359 2023 DIMP LA	376.0	12/31/23	LA PRYOR	Jurisdictional	117,319.36	TX	100.00%	117,319.36
70	1660291	DIMP	PO 90360 2023 DIMP	376.0	12/31/23	NATALIA & ENVIRONS	Jurisdictional	26,401.79	TX	100.00%	26,401.79
71	1660292	DIMP	PO 90361 2023 DIMP SAN	376.0	12/31/23	SAN ANTONIO AREA - RURAL	Jurisdictional	11,897.79	TX	100.00%	11,897.79

However, the 36.75% jurisdictional allocator is later applied to these investment amounts, which significantly reduces the total investment WTGU is able to recover from jurisdictional customers. For these reasons, the Company is requesting that it be able to fully recover from jurisdictional customers the full cost of the investments the Company makes to provide service to those customers. As calculated by Dr. Fairchild, the jurisdictional factor for GRIP filings going forward should be 51.22%. Crucially, the Company requests that this jurisdictional allocation factor should be applied only when investment benefits both jurisdictional and non-jurisdictional customers. It should not apply to investment that the Company can identify as purely for the benefit of jurisdictional customers.

Q. HOW IS THE COMPANY ABLE TO DETERMINE THAT SOME CAPITAL INVESTMENT BENEFITS ONLY JURISDICTIONAL CUSTOMERS?

A. The Company is able to identify certain capital investment that only jurisdictional customers benefit from, such as new residential subdivision projects, maintenance pipeline projects, as well as meters and measurement equipment. If a pipeline is built for a new residential development, then the Company can confidently determine that the new capital investment only benefits jurisdictional customers. DIMP projects also only benefit jurisdictional customers because they improve the safety, reliability, and integrity of the natural gas distribution systems that serve regulated customers. These projects target the infrastructure within the Company's regulated service areas such as residential neighborhoods in incorporated cities and related environs. This ensures that the investment benefits are localized to the customers whose rates are regulated through approved tariffs.

Q. DOES THE JURISDICTIONAL FACTOR AFFECT WHAT GROWTH AND BUSINESS OPPORTUNITIES THE COMPANY CAN VIABLY PURSUE?

A. Yes. Because the Company's GRIP formula is hampered by the jurisdictional factor, it cannot always build or invest in potential distribution systems that a competitor might determine are economically viable because the competitor could fully and expeditiously start recovering that capital investment through GRIP while the Company cannot. Likewise, when the Company considers whether to acquire older or distressed gas distribution systems and rehabilitate and incorporate those systems into the Company's system, the Company must consider that full recovery of those capital investment activities would not be possible under the current GRIP formula.

VII. SHARED SERVICES

Q. WHAT IS WTG DOWNSTREAM SERVICES, LLC?

A. WTGDS provides corporate support services to WTGU and various allocation methods as set out in its Cost Allocation Manual ("CAM"), attached as Exhibit AE-2, are used to transfer these expenses recorded on the books of the Company to the appropriate entity or entities. Its predecessor entity, JLD Shared Services, LLC was established in consultation with Commission Staff following the Company's 2013 rate case to provide a means to assign, allocate, record and pay certain employee earnings and various vendor expenditures that directly and/or indirectly benefit some or all of the WTG entities, including WTGU.

Q. WHAT CORPORATE SUPPORT SERVICES DOES WTGDS PROVIDE?

A. The support functions include but are not limited to accounting, information technology, communications infrastructure, human resource management (including payroll and benefit plans), insurance services, financial services, general administrative, regulatory compliance, environmental and land services, purchasing services, office infrastructure (including leasehold space and utilities), and professional services (including, but not limited to legal, accounting, engineering, and other consulting services).

Q. WHAT BENEFITS ARE PROVIDED THROUGH A CENTRALIZED CORPORATE SUPPORT SERVICES STRUCTURE?

A. A centralized Corporate Support Services structure allows all WTG entities, including the Company, to leverage resources across multiple business units, thereby giving the business units access to specialized skills and resources in an efficient and cost-effective manner. For example, accounting for employee benefits requires skilled and experienced individuals who must be able to analyze accounting standards related to employee benefits, understand the components of the benefit programs, and have the ability to discuss the benefit programs with actuaries. Having a centralized function eliminates the need for each of the business units to have that expertise separately, thus eliminating the need for duplication.

Q. HOW MUCH O&M EXPENSE DID EACH OF THE SERVICE COMPANY FUNCTIONS CHARGE WTGU IN THE TEST YEAR?

A. The table below shows WTGDS's costs and the amounts billed to WTGU for each of the functional areas in the test year:

	For the Test Year End December 31, 2023	
Service Company Functional Area	Total Billings (Thousand)	WTGU Billings (Thousand)*
Labor and Related Personnel Costs	45,081	11,343
Insurance Expense	13,363	908
Electricity	8,172	21
Overhead Burden	11,153	967
P-Card Purchases	1,055	394
Phone Expense	1,615	226
Other	10,025	339
Total WTGDS	90,463	14,198

Q. ARE THE AMOUNTS ASSIGNED TO WTGU AND OTHER AFFILIATES COST-BASED?

A. Yes. WTGDS bills all expenses at cost.

Q. ARE THE METHODS USED BY WTGDS TO BILL ALL AFFILIATES, INCLUDING WTGU, THE SAME?

A. Yes. All costs for a given service that are directly related to affiliates, including WTGU, are directly billed. If allocated, the costs are not higher than the prices charged by WTGDS for the same class of items to other affiliates.

Q. WHAT TYPE OF INFORMATION IS FOUND IN THE CAM?

A. The CAM documents the billing methodology used by WTGDS and details the major activities performed by the cost center and the cost assignment method for the cost center.

Q. IS AN ASSIGNMENT METHOD IDENTIFIED FOR EACH SERVICE COMPANY FUNCTION?

A. Yes. Each function is reviewed following guidelines outlined in the CAM to determine the proper method to assign costs to the cost centers within the function. The CAM outlines the allocation method for each WTGDS cost center.

Q. DOES THE COMPANY'S REQUEST FOR WTGDS EXPENSE MEET THE STATUTORY AFFILIATE STANDARD IN GURA § 104.055?

A. Yes. All affiliate costs included in this filing are reasonable and necessary costs of providing gas utility service, and the prices charged to WTGU are no higher than the prices charged by the supplying affiliate to other affiliates or to a non-affiliated person for the same item or class of items. Corporate costs are directly billed where possible, or allocated pursuant to the CAM where direct assignment is impractical.

VIII. <u>WINTER STORM URI REGULATORY ASSET</u>

Q. DID THE COMMISSION ISSUE ANY GUIDANCE RELATED TO EXTRAORDINARY EXPENSES A GAS UTILITY MIGHT HAVE TO INCUR DURING WINTER STORM URI?

A. Yes. The Commission issued a Notice on February 13, 2021, to Local Distribution Companies ("LDCs") authorizing LDCs to create a regulatory asset to record "extraordinary" costs incurred during Winter Storm Uri ("Regulatory Asset Notice"). In the Regulatory Asset Notice, the Commission acknowledged gas utilities may have to pay high prices for natural gas given the demand for gas during Winter Storm Uri and the Commission encouraged LDCs to ensure customers were provided with safe and reliable natural gas service.

Later, on June 17, 2021, the Commission issued another notice that explained the process LDCs could follow to determine and recover regulatory asset amounts and participate in a securitization process the legislature enacted following Winter Storm Uri. Even though WTGU did not participate in securitization, the notice the Commission issued in June 2021 identifies some of the information and documentation the Commission wanted to review to analyze extraordinary costs, and the Company is providing that type of information in this case.

Q. WHAT ACTIONS DID WTGU TAKE IN RESPONSE TO THE REGULATORY ASSET NOTICE?

A. Based on the Regulatory Asset Notice, WTGU created a regulatory asset on its books to book extraordinary costs the Company incurred to provide service to customers during the storm.

Q. PLEASE IDENTIFY THE COSTS IN THE REGULATORY ASSET.

A. WTGU's regulatory asset consists of $3,502,862.85 in extraordinary gas costs. WTGU is not requesting the carrying costs associated with this regulatory asset.

Q. HOW DID THE COMPANY CALCULATE THE AMOUNT OF EXTRAORDINARY GAS COSTS?

A. The process used to determine the extraordinary gas costs was to calculate the average daily gas price for February 2021 without the winter price dates included. This price was then multiplied by the volume to get a normalized gas cost. The remaining amount of the invoice was then recorded in the regulatory asset account as extraordinary gas costs. This calculation is addressed further in Mr. King's testimony.

More broadly, the regulatory asset account was for costs that were directly associated with the Company's response to Winter Storm Uri and would not have been incurred but for the winter storm. The Company did not use the asset for expenses that would be expected under normal or typical operating conditions such as regular labor, normal contractor costs, or capital projects.

Q. WHAT PROCESS DID THE COMPANY FOLLOW TO VERIFY THE ACCURACY OF THE GAS COST INVOICES IT RECEIVED FOR GAS PURCHASED AND DELIVERED TO CUSTOMERS DURING THE WINTER STORM?

A. The Company had several steps to verify the accuracy of the gas cost invoices it received for gas purchased and delivered to customers during the winter storm. Both volumes and prices were verified for each gas cost invoice. The prices were verified against published first of month indexes and gas daily indexes, and the volumes were verified against volume statements. These are reviewed by both the gas supply manager and the VP of Gas Marketing.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO AMOUNTS INCLUDED IN THE REGULATORY ASSET?

A. No.

Q. DO THE EXTRAORDINARY GAS COSTS INCLUDE AFFILIATE EXPENSES?

A. Yes. As explained in detail by Mr. King, WTGU obtains gas supply through its affiliate gas, WTG Gas Marketing, LLC ("WTGGM"). Mr. King also explains how the extraordinary gas costs included in the regulatory asset are reasonable and necessary costs of providing gas utility service, and the prices charged to WTGU are no higher than the prices charged by WTGGM to other affiliates or to non-affiliated persons.

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes, it does.

STATE OF TEXAS §
§
COUNTY OF MIDLAND §

AFFIDAVIT OF AMANDA EDGMON

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

1. "My name is Amanda Edgmon. I am over the age of eighteen (18) and fully competent to make this affidavit. The facts stated herein are true and correct based on my personal knowledge. My current position is Treasurer and Secretary and Regulatory Accountant for West Texas Gas Utility, LLC.
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.

Amanda Edgmon
Amanda Edgmon

SUBSCRIBED AND SWORN TO BEFORE ME by the said Amanda Edgmon on this 27th day of June 2024.

Jamie A. Mead
Notary Public, State of Texas

JAMIE A. MEAD
Notary Public, State of Texas
Comm. Expires 03-22-2026
Notary ID 133659307

GL ACCT	DESCRIPTION	FERC ACCT
725-005	MUNICIPAL DOMESTIC GAS SALES	480.0
725-010	RURAL DOMESTIC GAS SALES	480.0
725-015	GAS SALES-PUBLIC AUTH CITY	482.0
725-016	GAS SALES-PUBLIC AUTH RURAL	482.0
725-020	GAS SALES-INTERSTATE	483.0
725-025	SMALL COMM & IND	481.0
725-030	RURAL SMALL COMM & IND	481.0
725-035	LARGE COMM & IND	481.0
725-040	RURAL LARGE COMM & IND	481.0
725-045	IRRIGATION SALES	481.0
725-055	SALES FOR RESALE	483.0
725-058	LEAKAGE ALLOCATION REVENUE	481.0
725-075	SERVICE CHARGES	488.0
725-085	GAS TRANSPORTATION FEES	489.3
725-090	CONNECTION FEES	488.0
725-095	METER REPAIR - LABOR	488.0
725-100	SALES-REGULATORS,ETC	488.0
725-110	OTHER INCOME	495.0
725-115	RETURNED CHECK CHARGE	488.0
725-140	DRIP & CONDENSATE SALES	492.0
725-150	GAS GATHERING FEES	489.1
725-160	MISC TARIFF FEES	488.0
725-165	COLLECTION FEES	488.0
725-170	OVER/UNDER GAS COST REVENUES	807.0
725-200	INTERCOMPANY SALES/RECEIPTS	484.0
765-005	INTEREST INCOME NON-AFFILIATE	419.0
770-040	RENTAL INCOME	418.0
780-015	MISCELLANEOUS	421.0
780-100	EMPLOYEE FEE/OTHER REIMB	421.0
780-200	HEDGING GAINS/LOSSES	807.5
780-400	MARKED TO MARKET GAINS/LOSSES	807.5
800-005	TRANSMISSION LINE PURCHASES	803.0
800-015	GAS WELL GAS	800.0
800-025	GATHERING FEE	858.0
800-035	TRANSPORTATION FEE	858.0
800-150	ODORANT	874.0
800-155	COST OF PART SALES	813.0
800-175	COMPANY USE	812.0
900-005	OFFICE PAYROLL - SALARIED	920.0
900-010	OFFICE PAYROLL - HOURLY	920.0
900-016	OFFICE PAYROLL - OVERTIME	920.0
900-021	NON-CASH EMPLOYEE COMP	920.0
900-023	PROF SERV-COLLECTIONS	923.0
900-025	PROF SERV-LEGAL	923.0
900-030	PROF SERV-ACCTG	923.0
900-045	PROF SERV-OTHER	923.0

900-050	OVERHEAD BURDEN	923.0
900-055	CONTRACT LABOR	923.0
900-056	SECRETARIAL SERVICE	923.0
900-065	OFFICE SUPPLIES & EXPENSE	921.0
900-080	POSTAGE & FREIGHT	921.0
900-086	BOTTLED WATER	921.0
900-095	JANITORIAL SUPPLIES	921.0
900-096	SMALL TOOLS	921.0
900-100	TELEPHONE	921.0
900-105	ANSWERING SERVICE	921.0
900-130	ELECTRIC UTILITY	921.0
900-140	PAYROLL TAXES	408.2
900-145	AD VALOREM TAX	408.2
900-150	FRANCHISE TAX	408.2
900-160	OTHER TAXES	408.2
900-164	PART 192 COMPLIANCE - GENERAL	930.2
900-165	FILING FEES	930.2
900-166	DOT PIPELINE SAFETY USER FEE	930.2
900-167	PUBLIC AWARENESS	910.0
900-168	INTEGRITY MGMT TRANSMISSION	874.0
900-169	OPERATOR QUALIFICATIONS	874.0
900-170	LICENSES & PERMITS	930.2
900-171	UNIFORMS	874.0
900-175	INSURANCE-GROUP & PAYROLL	926.0
900-180	INSURANCE-OTHER	924.0
900-181	WORKMAN'S COMP CLAIMS PAID	926.0
900-185	PENSION PLAN	926.0
900-190	EMPLOYEE BENEFITS	926.0
900-195	EMPLOYEE EDUCATION	926.0
900-198	EMP PHYSCLS/ALCOHOL DRUG TESTS	926.0
900-205	AUTO OIL & GAS	930.2
900-215	EMPLOYEE EXPENSE - OTHER	930.2
900-221	LODGING	930.2
900-225	PILOT TIME	930.2
900-231	RENTAL FEES	931.0
900-240	OFFICE EQUIPMENT LEASE	931.0
900-250	STORAGE	931.0
900-255	SERVICE CHARGES	930.2
900-260	DUES & SUBSCRIPTIONS	930.2
900-265	DONATIONS	930.2
900-275	ENTERTAINMENT & MEALS	921.0
900-276	TRAVEL	921.0
900-290	PENALTIES, FINES, ETC	921.0
900-315	COMPUTER SOFTWARE - RENT	921.0
900-320	COMPUTER PAPER & FORMS	921.0
900-340	MAINTENANCE SUPPLIES	930.2
900-345	COMPUTER INTERNET SERVICE	921.0

900-350	COMPUTER SOFTWARE SUPPORT	921.0
900-370	CAPITALIZED OVERHEAD	920.0
900-382	SAFETY COMPLIANCE	926.0
900-400	RESALE EXPENSES - REBILLABLE	930.2
900-900	MISCELLANEOUS	930.2
915-010	OFFICE PAYROLL - HOURLY	870.0
915-015	FIELD PAYROLL - SALARIED	870.0
915-021	FIELD PAYROLL - OVERTIME	870.0
915-030	CONTR LBR-BCKHOE & DITCHG	874.0
915-035	CONTR LBR-WELDING	874.0
915-040	CONTRACT LBR-PUMPERS	874.0
915-045	CONTR LBR-MANUAL LABOR	874.0
915-050	CONTR LBR-OTHER	874.0
915-055	CONSULTING	874.0
915-059	PROF SERV-COLLECTIONS	874.0
915-060	PROF SERV-LEGAL	874.0
915-063	PROF SERV-OTHER	874.0
915-075	OFFICE SUPPLIES	880.0
915-076	MARKETING FEE	913.0
915-080	MAPS, XEROX, PRINTING	880.0
915-085	POSTAGE & FREIGHT	880.0
915-090	COFFEE BAR	880.0
915-091	BOTTLED WATER	880.0
915-095	TELEPHONE	880.0
915-100	ELECTRICITY UTILITIES	880.0
915-105	WATER UTILITIES	880.0
915-110	GAS UTILITIES	880.0
915-111	CLEANING, EXTERMINATING	880.0
915-114	TRASH HAULING	880.0
915-115	UTILITIES - OTHER	880.0
915-120	RADIO & ALARM	880.0
915-150	MISC RECEIPTS TAX	408.2
915-156	LICENSES AND TITLES	880.0
915-157	AD VALOREM TAXES	408.2
915-158	FILING FEES	880.0
915-161	PAYROLL TAX	408.2
915-165	OFFICE RENT	881.0
915-170	RENTS-OTHER	881.0
915-171	RENTAL FEES	881.0
915-174	OTHER LEASE EXPENSE	881.0
915-175	EQUIPMENT RENTALS	881.0
915-180	STORAGE CHARGES	930.2
915-190	AUTO OIL & GAS	930.2
915-205	DUES & SUBSCRIPTIONS	880.0
915-210	DONATIONS	880.0
915-211	BENEVOLENCES	930.2
915-215	ADVERTISING	913.0

915-216	PROMOTION EXPENSE	913.0
915-220	ENTERTAINMENT & MEALS	930.2
915-221	LODGING	930.2
915-222	TRAVEL	930.2
915-225	CHART INTEGRATION	874.0
915-226	GAS ANALYSES	874.0
915-227	SCADA - MEASUREMENT EQUIP	874.0
915-230	SVC STA & WHSE SUPPLIES	874.0
915-235	FIELD SUPP-PIPE & FITTG	874.0
915-240	FIELD SUPP-MEASURE EQUIP	874.0
915-245	FIELD SUPP-TOOLS	874.0
915-250	FIELD SUPP-OTHERS	874.0
915-255	FIELD SUPP-ON TRUCKS	874.0
915-256	SAFETY SUPPLIES	874.0
915-260	UNIFORMS	880.0
915-262	WELDING SUPPLIES	874.0
915-268	ENGINE ANTIFREEZE	880.0
915-270	LUBRICANTS & OILS	880.0
915-275	METHANOL	874.0
915-276	LAUNDROMAT	880.0
915-280	PROPANE	880.0
915-288	PIPELINE CHEMICALS	880.0
915-291	DAMAGES	874.0
915-292	RIGHT OF WAY - EASEMENT	874.0
915-294	PIPELINE LEASE EXPENSE	874.0
915-295	WATER HAULING/DISPOSAL	874.0
915-302	METER TESTING	874.0
915-303	PIPELINE EXPENSE	874.0
915-305	DELAY RENTALS	874.0
915-320	LEAK DETECTION	874.0
915-335	SERVICE CHARGE	880.0
915-340	CASH OVER/SHORT	880.0
915-382	SAFETY COMPLIANCE	874.0
915-400	EMPLOYEE BENEFITS	926.0
915-410	EMP PHYSCLS/ALCOHOL-DRUG TESTS	926.0
915-420	EMPLOYEE EDUCATION	926.0
915-425	COMPUTER INTERNET SERVICE	880.0
915-900	MISC	880.0
920-002	BUILDINGS, CANOPIES, DRIVEWAYS	894.0
920-003	ROLLING STOCK	894.0
920-004	SIGNAGE	894.0
920-005	ROLLING STOCK/REP & MAINT	894.0
920-010	AUTO & PU REP &	894.0
920-020	REP & MAINT/PROPANE TANK	894.0
920-021	SHOP EQUIPMENT RECALIBRATION	894.0
920-030	REP & MAINT-DISTRIBUTION LINE	887.0
920-031	R & M - DISTRIBUTION	887.0

920-035	REP & MAINT TRANSMISSION LINE	863.0
920-040	REP & MAINT-METER,REGLTR	889.0
920-041	R & M - METERS	889.0
920-045	REP & MAINT-ODOR & SFTY	889.0
920-046	CATHODIC PROTECTION	894.0
920-055	GENERATOR MAINT	888.0
920-065	TANKS & VESSELS MAINT	888.0
920-070	FIELD MEASUR EQUIP MAINT	889.0
920-075	PIPES VALVES & FITTINGS MAINT	889.0
920-080	ELECTRICAL MAINT	889.0
920-082	TAP, METER MAINT	889.0
920-083	AIR COMPRESSOR REPAIR	889.0
920-084	GAS COMPRESSOR PREVNTIVE MAINT	888.0
920-085	COMPRESSOR ENGINE MAINT	888.0
920-090	INSTRUMENTS & CONTROLS MAINT	894.0
920-095	SITE MAINTENANCE	894.0
920-105	REP & MAINT-STRUC & IMPROV	886.0
920-110	GROUNDS & EQUIPMENT	894.0
920-115	PLUMBING	894.0
920-120	COMMUNICATION EQUIPMENT	894.0
920-125	REPAIRS - OFFICE EQUIPMENT	894.0
920-130	MISC MAINTENANCE EXPENSE	894.0
920-140	LOCKS & KEYS	894.0
920-145	DOORS & WINDOWS	894.0
920-150	HEATING & AIR CONDITIONING	894.0
920-160	FENCES & GATES	894.0
920-165	PAINT, WALLS & TILES	894.0
920-170	EXTERMINATING	894.0
920-175	CLEANING & SUPPLIES	894.0
930-005	INTEREST EXPENSE NON-AFFILIATE	427.0
930-010	DEPRECIATION	403.0
930-015	AMORTIZATION	404.3
930-045	BAD DEBT EXPENSE	904.0
930-060	AMORTIZATION CIAC	403.1

GL Acct	Description	FERC
100-100	PETTY CASH	135.0
100-220	CASH OPER-WELLS FARGO BANK	131.0
100-309	CASH DEP-TRANS PECOS AREA	131.0
100-317	CASH DEP-SHAMROCK DISTRICT	131.0
100-321	CASH DEP-DALHART DISTRICT	131.0
100-327	CASH DEP-PLAINVIEW (NG)	131.0
100-330	CASH DEP-JUNCTION AREA	131.0
100-335	CASH DEP-AMARILLO AREA	131.0
100-340	CASH DEP-CANADIAN AREA	131.0
100-350	CASH DEP-WHEELER DISTRICT	131.0
100-366	CASH DEP-SAN ANTONIO AREA	131.0
100-370	CASH DEP-GUYMON AREA	131.0
100-374	CASH DEP-STRATFORD DISTRICT	131.0
100-430	CASH DEP-LUBBOCK AREA	131.0
105-205	CERTIFICATES OF DEPOSITS	136.0
120-005	INSUFF CHECK RETURN	143.0
120-032	UNRECOVERED GAS COST - OKLA	191.0
120-032	UNRECOVERED GAS COST - OKLA	191.0
120-035	UNRECOVERED OKLA DEMAND CHGS	191.0
120-035	UNRECOVERED OKLA DEMAND CHGS	191.0
120-140	A/R TRADE - NATURAL GAS	142.0
120-145	A/R OTHERS	143.0
120-180	A/R RATE CASE EXPENSES	142.0
120-185	A/R PIPELINE SURCHARGE TX	142.0
120-186	A/R OCC PUB UTILITY SURCHARGE	142.0
120-195	A/R OCC LUFG SURCHARGE	142.0
120-215	A/R COVID-19 EXPENSES	182.3
120-220	2021 WINTER WEATHER EVENT	182.3
125-111	RESERVE FOR BAD DEBTS - NG	144.0
125-111	RESERVE FOR BAD DEBTS - NG	144.0
126-100	A/R AFFILIATE	146.0
126-141	A/R WTG GAS MARKETING	146.0
128-017	ICT A/R WTG LIQUIDS DIVISION	146.0
140-100	P/P INSURANCE EXPENSE	165.0
140-110	P/P EXPENSE OTHER	165.0
140-112	P/P NAT GAS CONTRACT WGI SYS	165.0
150-275	INVENTORY-OTHER	154.0
150-400	INVENTORY-EGW	154.0
160-900	SUSPENSE	174.0
235-010	PIPELINE	101.0
235-012	METERS AND REGULATORS	101.0
240-001	PIPELINE	101.0
240-005	METERS & REGULATORS	101.0
240-010	COMPRESSORS	101.0
240-015	RIGHT-OF-WAY	101.0
240-015	RIGHT-OF-WAY	101.0

240-020	TESTING EQUIPMENT	101.0
240-020	TESTING EQUIPMENT	101.0
240-025	FIELD TOOLS	101.0
240-030	GAS DIST FACIL. -OTHER	101.0
241-001	PIPELINE	101.0
241-001	PIPELINE	101.0
241-005	METERS & REGULATORS	101.0
241-010	COMPRESSORS	101.0
241-020	TESTING EQUIPMENT	101.0
241-020	TESTING EQUIPMENT	101.0
241-025	FIELD TOOLS	101.0
241-030	GAS DIST FACILITY OTHER	101.0
250-010	PIPELINE	101.0
250-010	PIPELINE	101.0
250-020	METERS & REGULATORS	101.0
250-030	COMPRESSOR STATION EQUIP	101.0
250-040	RIGHT-OF-WAY	101.0
250-040	RIGHT-OF-WAY	101.0
250-045	MEASURING & REG STA EQUIP	101.0
250-050	OTHER EQUIPMENT	101.0
250-065	MEASUR & REG STA STRUCTURES	101.0
270-005	AUTOMOBILES	101.0
270-006	HEAVY ROLLING STOCK	101.0
270-007	TRAILERS	101.0
270-007	TRAILERS	101.0
270-011	EXCAVA. & CONSTR EQUIP	101.0
270-020	COMMUNICATION EQUIPMENT	101.0
270-025	OFFICE FURNISHINGS & EQUIPMENT	101.0
270-030	MAINTENANCE EQUIPMENT	101.0
270-035	FIELD EQUIPMENT	101.0
270-045	OTHER	101.0
270-065	DATA PROCESSING EQUIP	101.0
270-101	CIP - DISTRIBUTION PIPELINE	107.0
270-105	CIP - DISTR METERS/REGULATORS	107.0
270-110	CIP - TRANSMISSION PIPELINE	107.0
270-125	CIP - ROW, EASEMENTS, DAMAGES	107.0
271-005	AUTOMOBILES	101.0
271-006	HEAVY ROLLING STOCK	101.0
271-025	OFFICE FURNITURE & EQUIP	101.0
271-035	FIELD EQUIPMENT	101.0
271-045	OTHER	101.0
275-005	BUILDINGS	101.0
275-010	FENCING	101.0
275-025	LAND	101.0
275-035	LEASEHOLD IMPROVEMENTS	101.0
275-040	SITE IMPROVEMENT	101.0
275-040	SITE IMPROVEMENT	101.0

276-005	BUILDINGS	101.0
276-025	LAND	101.0
276-040	SITE IMPROVEMENTS	101.0
276-040	SITE IMPROVEMENTS	101.0
280-005	ORGANIZATION COST	101.0
280-010	RIGHT-OF-WAY	101.0
280-010	RIGHT-OF-WAY	101.0
280-065	FRANCHISE COSTS	101.0
280-075	CAPITALIZED SOFTWARE	101.0
280-100	MISC OTHER INT NON-AMORTIZING	101.0
281-010	RIGHT-OF-WAY	101.0
281-010	RIGHT-OF-WAY	101.0
281-070	OTHER	101.0
335-005	GAS GATHERING SYSTEMS	108.0
335-010	PIPELINE / PIPE	108.0
335-010	PIPELINE / PIPE	108.0
340-001	PIPELINE	108.0
340-001	PIPELINE	108.0
340-005	METERS & REGULATORS	108.0
340-010	COMPRESSORS	108.0
340-015	RIGHT-OF-WAY	108.0
340-015	RIGHT-OF-WAY	108.0
340-020	TESTING EQUIPMENT	108.0
340-020	TESTING EQUIPMENT	108.0
341-001	PIPELINE	108.0
341-001	PIPELINE	108.0
341-005	METERS & REGULATORS	108.0
341-010	COMPRESSORS	108.0
341-020	TESTING EQUIPMENT	108.0
341-020	TESTING EQUIPMENT	108.0
350-010	PIPELINE	108.0
350-010	PIPELINE	108.0
350-020	METERS & REGULATORS	108.0
350-030	COMPRESSOR STATION EQUIP	108.0
350-040	RIGHT-OF-WAY	108.0
350-040	RIGHT-OF-WAY	108.0
350-050	OTHER	108.0
350-060	COMPRESSOR STATION STRUCTURES	108.0
370-005	AUTOMOBILES	108.0
370-010	STEAM CLEANER	108.0
370-010	STEAM CLEANER	108.0
370-020	COMMUNICATION EQUIPMENT	108.0
370-025	OFFICE FURNISHINGS & EQUIPMENT	108.0
370-040	PULLING UNITS	108.0
370-040	PULLING UNITS	108.0
371-005	AUTOMOBILES	108.0
371-025	OFFICE FURNITURE & EQUIP	108.0

371-035	FIELD EQUIPMENT	108.0
371-045	OTHER	108.0
375-005	BUILDINGS	108.0
376-005	BUILDINGS	108.0
380-005	ORGANIZATION COST	108.0
380-010	RIGHT-OF-WAY	108.0
380-010	RIGHT-OF-WAY	108.0
380-065	FRANCHISE COSTS	108.0
380-100	MISC OTHER INT NON-AMORTIZING	108.0
381-010	RIGHT-OF-WAY	108.0
381-010	RIGHT-OF-WAY	108.0
400-005	A/P TRADE	232.0
400-010	A/P OTHER	232.0
400-015	A/P OTHER NG PURCHASES	232.0
400-036	A/P TEXAS GAS USERS ASSOC	232.0
400-120	A/P CONTRACT GAS PAYABLE TW	232.0
405-005	A/P AFFILIATES	234.0
405-030	A/P WTGM COMMODITY	234.0
420-005	CUSTOMER DEPOSITS	235.0
425-010	ACCR MISC RECEIPTS TAX	236.0
425-015	ACCR TEXAS SALES TAX	236.0
425-036	ACCR OKLA COUNTY TAX	236.0
425-037	ACCR OKLA FRANCHISE FEE	236.0
425-045	ACCR TEXAS FRANCHISE TAX	236.0
425-055	ACCR TEXAS CITY TAX	236.0
425-056	ACCR TEXAS COUNTY TAX	236.0
430-010	WELLS FARGO BANK TEXAS, N.A.	237.0
430-100	ACCRUED INTEREST OTHER	237.0
435-015	ACCR EXPENSES-OTHER	242.0
435-033	UNRECOVERED GAS COST - TX	242.0
435-033	UNRECOVERED GAS COST - TX	242.0
450-105	DEFERRED LIABILITY CIAC	101.0
450-110	DEFERRED COST OF GAS	253.0
450-120	DEFERRED MARK TO MARKET LOSS	245.0
605-100	EQUITY DISTRIB PAID/RECEIVED	216.0
617-000	YTD INCOME	216.0
617-000	RETAINED EARNINGS	216.0
617-000	RETAINED EARNINGS	216.0
617-000	RETAINED EARNINGS	216.0
617-000	RETAINED EARNINGS	216.0
635-275	MEMBERS' EQUITY	216.0

WTG DOWNSTREAM SERVICES, LLC
COST ALLOCATION MANUAL

Purpose

WTG Downstream Services, LLC ("WTGDS" or "Company") has been established to provide a means to assign, allocate, record and pay certain employee earnings and various vendor expenditures that directly and/or indirectly benefit some or all of the WTG entities. Various allocation methods, as set out in this Cost Allocation Manual ("CAM"), are used to transfer these expenses recorded on the books of the Company to the appropriate entity or entities. This CAM is applicable to WTGDS only and does not reflect further allocation practices applied to the books and records of affiliated entities for regulatory, contractual or financial reporting purposes.

Corporate Structure

Appendix A is an organization chart depicting the wholly owned subsidiaries of WTG Downstream LLC (the "Downstream Subsidiaries") and the wholly owned subsidiaries of WTG Downstream LLC's sister holding companies, WTG Fuels Holdings LLC (the "Fuels Subsidiaries") and WTG Midstream LLC (the "Midstream Subsidiaries" which together with the Downstream Subsidiaries and the Fuels Subsidiaries are collectively, the "WTG Subsidiaries"). WTG Downstream Holdings LLC ("WTG Downstream") is ultimately owned 80% by Stonepeak Remuda Investment Holdings LLC and 20% by the Estate of James Lee Davis, deceased. WTG Downstream Services, LLC (a wholly owned subsidiary of WTG Downstream) ("Downstream Services") is the W-2 employer of all employees who work exclusively for the Downstream Subsidiaries or the Fuels Subsidiaries. WTG Midstream LLC is the W-2 employer of all employees who work exclusively for the Midstream Subsidiaries. Downstream Services is also the W-2 employer of certain corporate level employees who render services to more than one (1) of the WTG Subsidiaries (the "Multi-Sector Employees").

WTG Downstream Holdings LLC

The following WTG Downstream Holdings LLC companies are affiliates of WTG Downstream Services, LLC:

> **West Texas Gas Utility, LLC** ("WTGU") is a regulated natural gas distribution and transmission company. Its operations are located in the panhandles of Oklahoma and Texas, the western and southern regions of Texas and in eastern New Mexico. WTGU has district office locations throughout Texas and Oklahoma with the corporate office located in Midland, Texas. WTGU maintains a separate set of books and records and directly pays the majority of its labor costs, general and administrative costs and operating and maintenance costs. WTGU is billed by the Company for certain personnel costs and shared services as discussed in this CAM.
>
> **WTG Gas Marketing, LLC.** ("WTGGM") is a wholesale and retail gas brokerage operation and functions out of the Midland, Texas corporate office location. WTGGM maintains a separate set of books and records and directly pays its operating costs. WTGGM is billed by the Company for personnel costs and certain shared services as discussed in this CAM.
>
> **Western Gas Interstate Company** ("WGI") is a regulated interstate pipeline utility with operations located in the Oklahoma and Texas panhandles. WGI maintains a separate set of books and

records and directly pays its operating and maintenance costs. WGI is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Gas Transmission Company ("WTGGT") is a regulated intrastate pipeline utility with operations located in the state of Texas. WTGGT maintains a separate set of books and records and directly pays its operating and maintenance costs. WTGGT is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Hugoton, LP ("WTGH") is a regulated interstate pipeline utility with its system extending from the southwestern part of Kansas into the Oklahoma panhandle. WTGH maintains a separate set of books and records and directly pays its operating and maintenance costs. WTGH is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Fuels Holdings LLC

The following WTG Fuels Holdings LLC companies are affiliates of WTG Downstream Services, LLC:

WTG Fuels, LLC ("WTGF") is a company whose assets include automated fuel operations, retail and wholesale petroleum product sales, and convenience stores locations situated primarily in Texas. WTGF maintains a separate set of books and records and directly pays its labor costs and operating and maintenance costs. WTGF is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

Gascard Partners, LP ("GCP") is a company whose assets include the "Gascard" automated card fueling system, transaction processing software, and hardware systems. GCP maintains a separate set of books and records and directly pays its operating and maintenance costs. Personnel costs for GCP are paid by WTGF and rebilled to the partnership. GCP is billed by the Company for certain shared services as discussed in this CAM.

WTG Midstream LLC

The following WTG Midstream LLC companies are affiliates of WTG Downstream Services, LLC:

Irion County Gas Plant ("Irion") is a gas processing plant located in Texas. Irion maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Gas Processing, LP ("WTGGP") is a gathering system and holds a 21% undivided interest in the Kinder Morgan Snyder Gas Plant. The owned gathering systems are located in Scurry, Howard, and Martin Counties in Texas. For accounting and reporting purposes, these systems are uniquely identified and maintained as separate reporting entities but are not separate legal entities and therefore are not separately here. WTGGP and each of the WTGGP gathering systems maintain a separate set of books and records and directly pay its operating and maintenance costs. WTGGP and WTGGP systems are billed for shared overhead services by the Company as discussed in this CAM.

Fuller Gas Plant ("Fuller") is a gas processing plant located in Texas. Fuller maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

East Vealmoor Plant ("East Vealmoor") is a gas processing plant located in Texas. East Vealmoor maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG North Permian Midstream LLC ("Sale Ranch") is a gas processing plant located in Texas. Sale Ranch maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Jameson, LP ("WTGJ") is a gas processing plant and gathering system located in Texas. WTGJ maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

Ledco, LLC ("Ledco") is a gas gathering system owned located in central and southern Louisiana. Ledco maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG NGL Marketing, LLC ("NGLMKT") is a natural gas liquids brokerage operation and functions out of the Midland, Texas corporate office location. NGLMKT maintains a separate set of books and records and directly pays its operating costs. NGLMKT is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG South Permian Midstream, LLC ("WTGSPM") is a gas processing plant located in Texas. WTGSPM maintains a separate set of books and records. It is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Gas Gathering Company, LLC ("WTGGG") is an intrastate pipeline utility with operations located in the state of Texas. WTGGG maintains a separate set of books and records and directly pays its operating and maintenance costs. WTGGG is billed by the Company for personnel costs and certain shared services as discussed in the CAM.

WTG NGL Pipeline Company, LLC ("NGLPL") is an intrastate liquids pipeline utility with operations located in the state of Texas. NGLPL maintains a separate set of books and records and directly pays its operating and maintenance costs. NGLPL is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

WTG Midstream Marketing, LLC ("WTGMM") is wholesale and retail gas brokerage operation and functions out of the Midland, Texas corporate office location. WTGMM maintains a separate set of books and records and directly pays its operating costs. WTGMM is billed by the Company for personnel costs and certain shared services as discussed in this CAM.

Low Country Power, LLC ("LCP") is an electricity generating company in which it uses its gas powered turbines to generate electricity for certain affiliated gas processing plants. LCP maintains a separate set of books and records and directly pays its operating and maintenance costs. LCP is billed for shared overhead services by the Company as discussed in this CAM.

Accounting Codes

WTG Downstream Services uses two main coding structures, one for overhead expenses and the other for rebillable expenses. Overhead expenses initially hit the income statement. At the end of each month all the expenses are zeroed out and rebilled based on the Allocation Method All Companies (9501). Rebillable expenses only hit the balance sheet and are recorded as a receivable.

The WTG Downstream Services coding structure for overhead expenses is shown below:

XXX	XXX	XXX	X-XXXXXX
Company #	GL Acct Major	GL Acct Minor	Billing Code
3 Digits	3 Digits	3 digits	1 Character 6 Digits (Max)

Example:

Company #	095
GL Account #	900-065
Billing Code	U-9501

- The company number assigned to WTG Downstream Services is number 095.
- The GL account number is made up of major and minor fields. The major field represents the account category such as general and administrative expense, code 900. The minor field includes the various types of accounts in that category such as office supplies, code 065 or telephone expense, code 100.
- The billing code field of U-9501 defines the expense as an overhead burden expense that will be rebilled based on the Allocation Method All Companies (9501).

The WTG Downstream Services coding structure for rebillable expenses is shown below:

XXX	XXX	XXX	X-XXXXXX	XXX
Company #	GL Acct Major	GL Acct Minor	Billing Code	Individual ID
3 Digits	3 Digits	3 digits	1 Character 6 Digits (Max)	6 Digits (Max)

Example:

Company #	095
GL Account #	120-145
Billing Code	U-99
Individual ID	16

- The company number assigned to WTG Downstream Services is number 095.
- The GL account number is made up of major and minor fields. When an affiliate is going to be rebilled for a certain expense, it is always coded to the GL Acct Major 120 (Accounts Receiveable) and GL Acct Minor 145 (A/R Other).
- The Billing Code field of U-99 defines the expense as a rebillable direct expense.
- The individual ID field defines the affiliate to be rebilled for the shared service cost incurred.

Definitions

Affiliate – Refers to legal entities owned by, or under the common control of the WTG companies.

Allocation Method All Companies (9501) – An allocation method used to allocate expenditures that are applicable to all affiliates. The components of the formula are total expense (including G&A, operating and maintenance expense), gross revenue, gross plant and net income.

Allocation Method Downstream (9502) – An allocation method used to allocate expenditures that are applicable to all affiliates that operate as a natural gas utility. The components of the formula are total expense (including G&A, operating and maintenance expense), gross revenue, gross plant and net income.

Allocation Method Midstream (9503) – An allocation method used to allocate expenditures that are applicable to any affiliates that primarily operate gas gathering and processing facilities. The components of the formula are total expense (including G&A, operating and maintenance expense), gross revenue, gross plant and net income.

Company – In general terms, Company refers to WTG Downstream Services, LLC.

Corporate Office – Headquarters for affiliates located in Midland, Texas.

Direct Assignment Method – The assignment of costs incurred by the Company on behalf of one or more affiliates that are specifically applicable to that affiliate or group of certain affiliates (referred to as Affiliate Specific Services within the Services Agreement).

Entity Group – For purposes of this report an entity group is a group of affiliated companies set up for outside audit purposes. Entity groups include WTGU and its subsidiaries, WTGGP and its affiliates and JLDHC and its subsidiaries.

Shared Services – Shared services are the support functions of the Company that serve the various WTG companies. These services are paid by WTGDS, recorded on its books and rebilled to affiliates through either direct assignment or a defined allocation method as applicable. The support functions include but are not limited to accounting, information technology, communications infrastructure, human resource management (including payroll and benefit plans), insurance services, financial services, general administrative, regulatory compliance, gas procurement, environmental and land services, purchasing services, office infrastructure (including leasehold space and utilities), and professional services (including, but not limited to legal, accounting, engineering, and other consulting services).

Shared Service | **Overhead Burden**

Description
Shared Services expenses as defined in this CAM.

Provider of Service
WTG Downstream Services, LLC

Affiliate Using Service
All affiliates

Allocation Method
Allocation Method All Companies (9501)

Other Notes
Overhead burden expenses hit the income statement of WTGDS. Each month, all the expenses are zeroed out and rebilled based on the Allocation Method All Companies (9501).

Shared Service | **Labor and Related Personnel Costs**

Description
Salaries and other personnel-related costs (e.g. health insurance, 401-K contributions, payroll taxes, etc).

Provider of Service
WTG Downstream Services, LLC

Affiliate Using Service
WTG Downstream Services will provide administrative services for Affiliates that do not maintain their own payroll reporting system. These costs are rebilled using one of the allocation methods described below.

Allocation Method
Labor costs are captured through direct time sheet entries of employees. Employees are assigned a company location code. Using that location code, calculated payroll amounts and corresponding payroll expense are tabulated and billed to the appropriate affiliate using one of the following methods:

- Direct Assignment (U-99 and respective company code)
- Allocation Method All Companies (9501)
- Allocation Method Downstream (9502)

Other Notes
Certain affiliates do not use this service because a payroll system is maintained by the affiliate and personnel costs are paid directly by the affiliate. These companies include the WTG Midstream companies.

Shared Service **Insurance Expense**

Description Insurance coverage for General Liability, Umbrella, Property, Auto, Workers Comp, Liquor Liability and Miscellaneous Other Fees

Provider of Service WTG Downstream Services, LLC

Affiliate Using Service All affiliates

Allocation Method Various Allocation Methods
Premiums for insurance coverage are rebilled using the various allocation methods shown below.

General Liability – This allocation method is based on through-put volumes for WTG and Plants and gallons for WTG Fuels. Volumes used are for the twelve month period ending March 31st of each year. (Basin & WTNB are excluded from this allocation because they have their own General Liability policies. JLD is also excluded from this allocation.)
Umbrella – The allocation method is the weighted average of Gross Revenue, Expenses including G&A, Operating and R&M and Payroll expense. Period includes the twelve months of the most recent calendar year end.
Property – Insured values have been defined based on plant. The percentage of the affiliate company's insured value to the total plant value is applied to the premium total and billed to the respective affiliate. (WTGX and Basin are excluded from this method and use a pre-determined property value.)
Auto – Vehicle count is used as allocation method for auto premium.
Workers Comp – Payroll expense at calendar year end is used for allocation. The percentage of the individual affiliate payroll expense to the total of all affiliate's payroll expense is applied to the premium total and billed to the respective affiliate.
Liquor Liability – The premium for liquor liability is charged directly to WTG Fuels, Inc.
Miscellaneous Other – Premium coverage for other insurance fees is allocated equally among the affiliated companies.

Insurance costs are paid out of WTGDS and assigned to the appropriate affiliate.

Other Notes Currently, insurance coverage is for the period from June 1st to May 31st each year. Premium allocations are recalculated annually using data from affiliate financial statements for the most recent calendar year end.

Shared Service	**P-Card Purchases**
Description	Select employees have been issued a Bank Card which can be used for company use in the purchase of certain items.
Provider of Service	WTG Downstream Services, LLC
Affiliate Using Service	All affiliates, as applicable
Allocation Method	Expenses for P-Card purchases are allocated using the following methods. These costs are paid out of WTGDS and then rebilled to the appropriate affiliate using the following: • Direct Assignment (U-99 and respective company code) • Allocation Method All Companies (9501) • Allocation Method Downstream (9502) • Allocation Method Midstream (9503)
Other Notes	Bank card charges are paid monthly to Wells Fargo out of WTGDS.

Shared Service	**Phone – Wireless and Wireline Expense**
Description	WTGDS utilizes the company Advantix to manage all the wireless and landline accounts across all companies
Provider of Service	WTG Downstream Services, LLC
Affiliate Using Service	All affiliates, as applicable
Allocation Method	Expenses for phone services are allocated using the following methods. These costs are paid out of WTGDS and then rebilled to the appropriate affiliate using the following: • Direct Assignment (U-99 and respective company code) • Allocation Method All Companies (9501) • Allocation Method Downstream (9502) • Allocation Method Midstream (9503)
Other Notes	Wireline and Wireless charges are paid to OneSource monthly out of WTGDS.

Shared Service	**Electricity**
Description	WTGDS utilizes the company BP Energy Retail Company LLC to manage some of the electricity accounts across all companies
Provider of Service	WTG Downstream Services, LLC
Affiliate Using Service	All affiliates, as applicable
Allocation Method	Electricity charges are are paid out of WTGDS and then rebilled to the appropriate affiliate using the following: • Direct Assignment (U-99 and respective company code)
Other Notes	Electricity charges are paid to BP monthly out of WTGDS.

Shared Service	**Affiliate Specific Services**
Description	Expense includes any specifically identifiable expense incurred for one or more affiliate for Affiliate Specific Services which are not offered to all affiliates under the Services Agreement
Provider of Service	WTG Downstream Services LLC
Affiliate Using Service	All affiliates, as applicable
Allocation Method	Direct Assignment Method
Other Notes	

Asset No.	Project Reason	Project Description	FERC No.	In Service Date	Customers Benefited	Customers Benefited	Total Project Cost	State	Allocation Factor	Texas Allocated Cost	Year
3560307	System Integrity	REPLACE 240' 6" TRANS	367.0	231231	CANADIAN AREA TX - RURAL	Both	16,455.00	TX	100%	16,455.00	2023
3560310	System Integrity	LEAK REPAIR ON 6" TRANS	367.0	231231	CANADIAN AREA TX - RURAL	Both	12,885.00	TX	100%	12,885.00	2023
3560311	System Integrity	22" LEAK REPAIR	367.0	231231	DALHART AREA - RURAL	Both	12,610.00	TX	100%	12,610.00	2023
3560329	System Integrity	REPAIR PIPELINE WELDED	367.0	231231	SAN ANTONIO AREA - RURAL	Jurisdictional	8,415.00	TX	100%	8,415.00	2023
3560330	System Integrity	PUMPKIN INSTALL	367.0	231231	CANADIAN AREA TX - RURAL	Both	8,090.00	TX	100%	8,090.00	2023
3560337	System Integrity	LEAK REPAIR SE OF WALKA	367.0	231231	CANADIAN AREA TX - RURAL	Both	5,170.00	TX	100%	5,170.00	2023
3560338	System Integrity	LEAK REPAIR S OF WALKA	367.0	231231	CANADIAN AREA TX - RURAL	Both	6,145.00	TX	100%	6,145.00	2023
3560340	System Integrity	LEAK REPAIR TRANS LINE	367.0	231231	CANADIAN AREA TX - RURAL	Both	5,615.00	TX	100%	5,615.00	2023
3560345	System Integrity	LEAK REPAIR HWY 33	367.0	231231	CANADIAN AREA TX - RURAL	Both	5,270.00	TX	100%	5,270.00	2023
3560364	System Growth	PO 27644 LOOP 410 STATION	367.0	231231	SAN ANTONIO AREA - RURAL	Jurisdictional	19,713.03	TX	100%	19,713.03	2023
3560407	System Growth	PO 28896 ROW WHISTLER/	367.0	231231	SAN ANTONIO AREA - RURAL	Jurisdictional	29,695.76	TX	100%	29,695.76	2023
3660226	Measurement	TOTALFLOW CONFIGURED AND	369.1	230131	CANADIAN AREA TX - RURAL	Both	5,071.87	TX	100%	5,071.87	2023
3606534	Measurement	TOTALFLOW USED 6213	369.1	230930	CANADIAN AREA TX - RURAL	Both	3,688.60	TX	100%	3,688.60	2023
160249	System Growth	TURPIN NORTH EXTENSION	376.0	230731	BEAVER OK	Out of State	12,000.00	OK	0%	-	2023
160260	System Integrity	PO 28321 RELOCATE 3,000FT	376.0	231231	BEAVER OK	Out of State	30,735.24	OK	0%	-	2023
160265	System Integrity	PO 28696 REPLACE 2-MILE	376.0	231231	TEXHOMA OK	Out of State	93,029.56	OK	0%	-	2023
160266	System Growth	PO 28837 SMITHFIELD FOODS	376.0	231231	BEAVER OK	Out of State	123,033.82	OK	0%	-	2023
160285	DIMP	PO 90353 2023 DIMP	376.0	231231	TEXHOMA OK	Out of State	738,289.70	OK	0%	-	2023
160286	DIMP	PO 90355 2023 DIMP BOISE	376.0	231231	BOISE CITY OK	Out of State	29,812.27	OK	0%	-	2023
160287	DIMP	PO 90356 2023 DIMP BEAVER	376.0	231231	BEAVER OK	Out of State	225,477.34	OK	0%	-	2023
160327	System Integrity	OPTIMA GAS LEAK REPAIR	376.0	231231	BEAVER OK	Out of State	8,886.96	OK	0%	-	2023
160376	System Growth	PO 28237 BUCK FARMS	376.0	231231	TEXHOMA OK	Out of State	3,829.27	OK	0%	-	2023
160377	System Growth	PO 28244 LANDON MEEKS	376.0	231231	TEXHOMA OK	Out of State	3,731.00	OK	0%	-	2023
160382	System Growth	PO 28328 DRY TRAILS	376.0	231231	BEAVER OK	Out of State	5,378.86	OK	0%	-	2023
1660232	System Integrity	LOWER AND REPLACE 6"	376.0	230331	DALHART AREA - RURAL	Non-Jurisdictional	28,740.00	TX	100%	28,740.00	2023
1660254	System Growth	PO 28205 ENCLAVE AT	376.0	231231	LUBBOCK	Jurisdictional	57,970.58	TX	100%	57,970.58	2023
1660255	System Growth	PO 28206 ENCLAVE AT	376.0	231231	LUBBOCK	Jurisdictional	66,869.54	TX	100%	66,869.54	2023
1660256	System Growth	PO 28236 MAGNOLIA ESTATES	376.0	231231	LUBBOCK AREA - RURAL	Jurisdictional	136,088.85	TX	100%	136,088.85	2023
1660257	System Growth	PO 28242 EVEREST HEIGHTS	376.0	231231	LUBBOCK	Jurisdictional	207,622.54	TX	100%	207,622.54	2023
1660258	System Growth	PO 28279 FOUNTAIN HILLS	376.0	231231	LUBBOCK	Jurisdictional	41,906.49	TX	100%	41,906.49	2023
1660259	System Growth	PO 28295 PARK HILL	376.0	231231	LUBBOCK AREA - RURAL	Jurisdictional	80,607.19	TX	100%	80,607.19	2023
1660261	System Growth	PO 28369 THE OVERLOOK	376.0	231231	LUBBOCK	Jurisdictional	221,330.69	TX	100%	221,330.69	2023
1660262	System Growth	PO 28385 LITTLE RED	376.0	231231	LUBBOCK	Jurisdictional	30,075.23	TX	100%	30,075.23	2023
1660263	System Growth	PO 28443 SOLARIS @ BROOKE	376.0	231231	LUBBOCK	Jurisdictional	94,863.18	TX	100%	94,863.18	2023
1660267	System Growth	PO 28264 HATTON PLACE	376.0	231231	LUBBOCK	Jurisdictional	24,072.44	TX	100%	24,072.44	2023
1660268	DIMP	PO 90318 2023 DIMP KERMIT	376.0	231231	KERMIT & ENVIRIONS	Jurisdictional	1,111,088.84	TX	100%	1,111,088.84	2023
1660269	DIMP	PO 90321 2023 DIMP VAN	376.0	231231	VAN HORN & ENVIRONS	Jurisdictional	306,976.74	TX	100%	306,976.74	2023
1660270	DIMP	PO 90322 2023 DIMP	376.0	231231	TRANS PECOS AREA - RURAL	Jurisdictional	167,720.29	TX	100%	167,720.29	2023
1660271	DIMP	PO 90325 2023 DIMP	376.0	231231	JUNCTION & ENVIRONS	Jurisdictional	23,729.29	TX	100%	23,729.29	2023
1660272	DIMP	PO 90326 2023 DIMP MENARD	376.0	231231	MENARD & ENVIRONS	Jurisdictional	263,932.01	TX	100%	263,932.01	2023
1660273	DIMP	PO 90327 2023 DIMP SONORA	376.0	231231	SONORA & ENVIRONS	Jurisdictional	489,867.95	TX	100%	489,867.95	2023
1660274	DIMP	PO 90328 2023 DIMP EDEN	376.0	231231	EDEN & ENVIRONS	Jurisdictional	597,780.73	TX	100%	597,780.73	2023
1660275	DIMP	PO 90329 2023 DIMP	376.0	231231	CHRISTOVAL ENVIRONS	Jurisdictional	3,376.69	TX	100%	3,376.69	2023
1660276	DIMP	PO 90332 2023 DIMP	376.0	231231	CANADIAN & ENVIRONS	Jurisdictional	1,099,462.73	TX	100%	1,099,462.73	2023
1660277	DIMP	PO 90333 2023 DIMP	376.0	231231	WHEELER TX & ENVIRONS	Jurisdictional	742,078.17	TX	100%	742,078.17	2023
1660278	DIMP	PO 90334 2023 DIMP	376.0	231231	SHAMROCK & ENVIRONS	Jurisdictional	734,159.58	TX	100%	734,159.58	2023
1660279	DIMP	PO 90335 2023 DIMP	376.0	231231	HIGGINS & ENVIRONS	Jurisdictional	6,562.38	TX	100%	6,562.38	2023
1660280	DIMP	PO 90336 2023 DIMP	376.0	231231	DARROUZETT & ENVIRONS	Jurisdictional	6,299.88	TX	100%	6,299.88	2023
1660281	DIMP	PO 90337 2023 DIMP	376.0	231231	FOLLETT & ENVIRONS	Jurisdictional	448,219.71	TX	100%	448,219.71	2023
1660282	DIMP	PO 90338 2023 DIMP MIAMI	376.0	231231	MIAMI & ENVIRONS	Jurisdictional	72,438.11	TX	100%	72,438.11	2023
1660283	DIMP	PO 90340 2023 DIMP	376.0	231231	CANADIAN AREA TX - RURAL	Jurisdictional	49,773.52	TX	100%	49,773.52	2023
1660284	DIMP	PO 90349 2023 DIMP	376.0	231231	TEXLINE & ENVIRONS	Jurisdictional	26,747.06	TX	100%	26,747.06	2023
1660288	DIMP	PO 90357 2023 DIMP	376.0	231231	SOMERSET & ENVIRONS	Jurisdictional	1,441,222.97	TX	100%	1,441,222.97	2023
1660289	DIMP	PO 90358 2023 DIMP DEVINE	376.0	231231	DEVINE & ENVIRONS	Jurisdictional	8,923.34	TX	100%	8,923.34	2023
1660290	DIMP	PO 90359 2023 DIMP LA	376.0	231231	LA PRYOR	Jurisdictional	117,319.36	TX	100%	117,319.36	2023
1660291	DIMP	PO 90360 2023 DIMP	376.0	231231	NATALIA & ENVIRONS	Jurisdictional	26,401.79	TX	100%	26,401.79	2023
1660292	DIMP	PO 90361 2023 DIMP SAN	376.0	231231	SAN ANTONIO AREA - RURAL	Jurisdictional	11,897.79	TX	100%	11,897.79	2023
1660294	System Growth	PO 28480 SOUTH COOPER	376.0	231231	LUBBOCK	Jurisdictional	68,207.09	TX	100%	68,207.09	2023
1660306	System Integrity	ANODES, TEST POINTS AND	376.0	231231	DALHART AREA - RURAL	Both	25,800.00	TX	100%	25,800.00	2023
1660308	System Growth	11 NEW WELLS COUNTY RD	376.0	231231	DALHART AREA - RURAL	Non-Jurisdictional	13,865.00	TX	100%	13,865.00	2023
1660315	System Integrity	LEAK REPAIR 4" STEEL LINE	376.0	231231	CANADIAN AREA TX - RURAL	Both	10,615.00	TX	100%	10,615.00	2023
1660323	System Integrity	REPAIR LEAK ON NORTH	376.0	231231	CANADIAN AREA TX - RURAL	Both	9,365.00	TX	100%	9,365.00	2023
1660344	System Integrity	3 PUMPKINS	376.0	231231	DALHART AREA - RURAL	Both	5,308.88	TX	100%	5,308.88	2023
1660351	System Integrity	PIPELINE REPAIR 1" TAP	376.0	231231	VAN HORN & ENVIRONS	Jurisdictional	5,650.00	TX	100%	5,650.00	2023
1660353	System Integrity	6" CATHOLIC ISOLATION	376.0	231231	CANADIAN AREA TX - RURAL	Both	6,425.80	TX	100%	6,425.80	2023
1660358	System Integrity	LEAK REPAIRS WILSON	376.0	231231	CANADIAN AREA TX - RURAL	Both	13,294.70	TX	100%	13,294.70	2023
1660359	System Growth	PO 25701 WILD FLOWER	376.0	231231	AMARILLO	Jurisdictional	399,040.12	TX	100%	399,040.12	2023
1660360	System Growth	PO 27013 SPRING CANYON	376.0	231231	AMARILLO AREA - RURAL	Jurisdictional	436,627.21	TX	100%	436,627.21	2023
1660361	System Growth	PO 27462 ELDORADO EXT	376.0	231231	JUNCTION & ENVIRONS	Jurisdictional	385,695.77	TX	100%	385,695.77	2023
1660363	System Growth	PO 27615 GOODWELL	376.0	231231	DALHART AREA - RURAL	Non-Jurisdictional	5,059.52	TX	100%	5,059.52	2023
1660365	System Growth	PO 27842 DARIN WILLIAMS	376.0	231231	GROOM & ENVIRONS	Non-Jurisdictional	3,234.16	TX	100%	3,234.16	2023
1660366	System Growth	PO 27879 GOODNIGHT SYSTEM	376.0	231231	AMARILLO AREA - RURAL	Jurisdictional	49,530.88	TX	100%	49,530.88	2023
1660367	System Growth	PO 27916 MESQUITE RIDGE	376.0	231231	AMARILLO AREA - RURAL	Jurisdictional	82,804.47	TX	100%	82,804.47	2023
1660368	System Growth	PO 27917 CANYON SCHOOL	376.0	231231	CANYON	Jurisdictional	1,685.00	TX	100%	1,685.00	2023
1660369	System Growth	PO 27923 PACE 8 PROJECT	376.0	231231	SOMERSET & ENVIRONS	Jurisdictional	198,526.85	TX	100%	198,526.85	2023
1660370	System Growth	PO 28112 HDDEN HILLS	376.0	231231	CANADIAN AREA TX - RURAL	Jurisdictional	21,576.70	TX	100%	21,576.70	2023
1660371	System Integrity	PO 28137 REGULATOR	376.0	231231	SOMERSET & ENVIRONS	Jurisdictional	410,055.76	TX	100%	410,055.76	2023
1660372	System Growth	PO 28140 WILDHORSE	376.0	231231	TRANS PECOS AREA - RURAL	Non-Jurisdictional	9,396.95	TX	100%	9,396.95	2023
1660373	System Growth	PO 28153 MILWUAKEE	376.0	231231	LUBBOCK	Jurisdictional	39,782.64	TX	100%	39,782.64	2023

1660378	System Growth	PO 28252 LULING DIST	376.0	231231	SOMERSET & ENVIRONS	Jurisdictional	38,766.00	TX	100%	38,766.00	2023
1660379	System Growth	PO 28260 GOODNIGHT EXT	376.0	231231	AMARILLO	Jurisdictional	62,567.16	TX	100%	62,567.16	2023
1660380	System Growth	PO 28263 STRATFORD	376.0	231231	STRATFORD & ENVIRONS	Jurisdictional	22,009.74	TX	100%	22,009.74	2023
1660381	System Growth	PO 28303 FARIA - EXUM	376.0	231231	DALHART AREA - RURAL	Non-Jurisdictional	2,040,917.04	TX	100%	2,040,917.04	2023
1660383	System Growth	PO 28402 INDIANA & LOOP	376.0	231231	LUBBOCK	Jurisdictional	166,410.14	TX	100%	166,410.14	2023
1660384	System Growth	PO 28439 MCCORMICK	376.0	231231	AMARILLO	Jurisdictional	9,255.58	TX	100%	9,255.58	2023
1660385	System Growth	PO 28449 CHAMPION FEEDERS	376.0	231231	AMARILLO AREA - RURAL	Non-Jurisdictional	93,707.40	TX	100%	93,707.40	2023
1660386	System Growth	PO 28478 DOUBLE JF	376.0	231231	DALHART AREA - RURAL	Non-Jurisdictional	51,120.19	TX	100%	51,120.19	2023
1660387	System Growth	PO 28491 TRAILS AT STONE	376.0	231231	LUBBOCK AREA - RURAL	Jurisdictional	77,757.04	TX	100%	77,757.04	2023
1660388	System Growth	PO 28492 ROXANNE CARTER	376.0	231231	GROOM & ENVIRONS	Jurisdictional	5,314.24	TX	100%	5,314.24	2023
1660389	System Growth	POP 28493 TIERRA SANTA	376.0	231231	GROOM & ENVIRONS	Jurisdictional	56,599.95	TX	100%	56,599.95	2023
1660390	System Growth	PO 28496 TX STATE PARK	376.0	231231	JUNCTION & ENVIRONS	Jurisdictional	14,382.85	TX	100%	14,382.85	2023
1660391	System Growth	PO 28527 RV PARK LINE	376.0	231231	LUBBOCK AREA - RURAL	Jurisdictional	3,600.00	TX	100%	3,600.00	2023
1660393	System Growth	PO 28532 114TH & SLIDE	376.0	231231	LUBBOCK	Jurisdictional	4,500.00	TX	100%	4,500.00	2023
1660394	System Growth	PO 28539 GARDNER EXT	376.0	231231	GROOM & ENVIRONS	Jurisdictional	968.75	TX	100%	968.75	2023
1660395	System Growth	PO 28540 EVEREST HEIGHTS	376.0	231231	LUBBOCK	Jurisdictional	157,106.01	TX	100%	157,106.01	2023
1660396	System Growth	PO 28553 BLAKE THRASH	376.0	231231	LUBBOCK AREA - RURAL	Jurisdictional	5,499.19	TX	100%	5,499.19	2023
1660397	System Growth	PO 28587 WHITE DEER LINE	376.0	231231	WHITE DEER & ENVIRONS	Jurisdictional	6,096.32	TX	100%	6,096.32	2023
1660398	System Growth	PO 28609 CANADIAN ALT GAS SUPP	376.0	231231	CANADIAN & ENVIRONS	Both	146,329.50	TX	100%	146,329.50	2023
1660399	System Growth	PO 28616 BARITE GRINDING	376.0	231231	TRANS PECOS AREA - RURAL	Jurisdictional	14,808.75	TX	100%	14,808.75	2023
1660400	System Growth	PO 28635 PREMIER TRUCK	376.0	231231	AMARILLO	Jurisdictional	244,498.93	TX	100%	244,498.93	2023
1660401	System Growth	PO 28654 1450 TXDOT BORE	376.0	231231	TRANS PECOS AREA - RURAL	Jurisdictional	3,845.06	TX	100%	3,845.06	2023
1660402	System Growth	PO 28663 4TH STREET	376.0	231231	LUBBOCK	Jurisdictional	154,471.27	TX	100%	154,471.27	2023
1660403	System Growth	PO 28682 SPRING CANYON	376.0	231231	AMARILLO	Jurisdictional	67,717.53	TX	100%	67,717.53	2023
1660404	System Growth	PO 28708 SECO/TGU GAS	376.0	231231	SAN ANTONIO AREA - RURAL	Jurisdictional	10,578.80	TX	100%	10,578.80	2023
1660405	System Growth	PO 28746 ABDIEL PEREZ	376.0	231231	GROOM & ENVIRONS	Jurisdictional	7,874.85	TX	100%	7,874.85	2023
1660406	System Growth	PO 28883 LOWER HUB 2	376.0	231231	DALHART AREA - RURAL	Non-Jurisdictional	24,390.00	TX	100%	24,390.00	2023
1660408	System Growth	PO 28947 KELLERVILLE	376.0	231231	CANADIAN AREA TX - RURAL	Jurisdictional	24,285.00	TX	100%	24,285.00	2023
1660422	System Growth	98TH AND ALCOVE TO UPLAND	376.0	231231	LUBBOCK	Jurisdictional	92,460.00	TX	100%	92,460.00	2023
1760375	System Growth	PO 28207 ALLSUPS PROJECT	376.0	231231	CLAUDE & ENVIRONS	Jurisdictional	5,250.00	TX	100%	5,250.00	2023
160243	Measurement	ROOTS METER 11C175 CTR	378.0	230430	BEAVER OK	Out of State	6,998.15	OK	0%	-	2023
160308	Measurement	METER REPAIRS	378.0	231231	BOISE CITY OK	Out of State	14,970.51	OK	0%	-	2023
206527	Measurement	3 ROOTS METERS, 3M175 CD	378.0	230831	BEAVER OK	Out of State	7,176.91	OK	0%	-	2023
260234	Measurement	EC350 ELECTRONIC VOLUME	378.0	230331	TEXHOMA OK	Out of State	4,909.15	OK	0%	-	2023
260235	Measurement	EC350 ELECTRONIC VOLUME	378.0	230331	TEXHOMA OK	Out of State	7,364.09	OK	0%	-	2023
260248	Measurement	EC350 CORRECTORS	378.0	230630	BEAVER OK	Out of State	12,459.01	OK	0%	-	2023
260312	Measurement	METER REPAIRS	378.0	231231	BEAVER OK	Out of State	12,538.21	OK	0%	-	2023
260313	Measurement	METER REPAIRS	378.0	231231	TEXHOMA OK	Out of State	11,715.86	OK	0%	-	2023
260314	Measurement	METER REPAIRS	378.0	231231	TEXHOMA OK	Out of State	10,942.47	OK	0%	-	2023
260328	Measurement	METER REPAIRS 750/800	378.0	231231	BEAVER OK	Out of State	8,845.72	OK	0%	-	2023
260349	Measurement	METER REPAIRS	378.0	231231	BOISE CITY OK	Out of State	3,811.78	OK	0%	-	2023
260355	Measurement	REBUILD DIAPHRAGM METERS	378.0	231231	BEAVER OK	Out of State	8,451.41	OK	0%	-	2023
260409	Measurement	METER REPAIRS	378.0	231231	BEAVER OK	Out of State	11,407.14	OK	0%	-	2023
260410	Measurement	METER REPAIRS	378.0	231231	BEAVER OK	Out of State	13,167.17	OK	0%	-	2023
1660362	Measurement	PO 27550 FARWELL SCHOOL	378.0	231231	FARWELL & ENVIRONS	Jurisdictional	12,229.67	TX	100%	12,229.67	2023
1706523	Measurement	REBUILT DIAPHRAGM METER	378.0	230831	SAN ANTONIO AREA - RURAL	Jurisdictional	2,089.41	TX	100%	2,089.41	2023
1706524	Measurement	DRESSER #400 IMC/W2 PTZ	378.0	230831	TRANS PECOS AREA - RURAL	both	2,628.14	TX	100%	2,628.14	2023
1706525	Measurement	ROOTS METER, 2M175 CTR	378.0	230831	TRANS PECOS AREA - RURAL	both	2,156.76	TX	100%	2,156.76	2023
1706528	Measurement	ROOTS METER, 11M175 CD	378.0	230930	GROOM & ENVIRONS	both	5,157.06	TX	100%	5,157.06	2023
1706529	Measurement	SICK 4" FS600 ULTRA SONIC	378.0	230930	DALHART AREA - RURAL	both	56,047.52	TX	100%	56,047.52	2023
1706530	Measurement	243-RPCB 2" REGULATOR, 1"	378.0	230930	MIAMI & ENVIRONS	both	2,320.05	TX	100%	2,320.05	2023
1706531	Measurement	SENSUS 243-RPCB 2"	378.0	230930	MIAMI & ENVIRONS	both	2,224.76	TX	100%	2,224.76	2023
1706532	Measurement	SENSUS 243-RPC STANDARD	378.0	230930	MIAMI & ENVIRONS	both	1,912.50	TX	100%	1,912.50	2023
1706533	Measurement	TOTALFLOW, XRC6490 W/MTG.	378.0	230930	LUBBOCK	Jurisdictional	4,812.69	TX	100%	4,812.69	2023
1706536	Measurement	METER ROTARY 3.2M FLANGED	378.0	231031	SAN ANTONIO AREA - RURAL	Jurisdictional	2,094.64	TX	100%	2,094.64	2023
1706537	Measurement	SENSUS REGULATOR, 2" BODY	378.0	231031	CANADIAN & ENVIRONS	both	2,124.47	TX	100%	2,124.47	2023
1760226	Measurement	ROOTS METER 2M175 CTR	378.0	230228	TRANS PECOS AREA - RURAL	both	1,897.78	TX	100%	1,897.78	2023
1760227	Measurement	ROOTS METER 2M175 CTR 2"	378.0	230228	TRANS PECOS AREA - RURAL	both	1,891.74	TX	100%	1,891.74	2023
1760228	Measurement	ROOTS METER 2M175 IMCW/2	378.0	230228	TRANS PECOS AREA - RURAL	both	4,830.91	TX	100%	4,830.91	2023
1760229	Measurement	DRESSER #400 IMC/W2 PTZ	378.0	230228	TRANS PECOS AREA - RURAL	both	2,010.82	TX	100%	2,010.82	2023
1760230	Measurement	FS500 SICK ULTRASONIC	378.0	230228	DALHART AREA - RURAL	both	16,742.18	TX	100%	16,742.18	2023
1760233	Measurement	REBUILT ROTARY METERS	378.0	230331	DALHART AREA - RURAL	both	9,562.50	TX	100%	9,562.50	2023
1760236	Measurement	REBUILT ROTARY METER	378.0	230430	DALHART AREA - RURAL	both	8,796.59	TX	100%	8,796.59	2023
1760237	Measurement	FLOW COMPUTER	378.0	230430	TRANS PECOS AREA - RURAL	both	5,457.00	TX	100%	5,457.00	2023
1760238	Measurement	KGM 2013 METER	378.0	230430	SOMERSET & ENVIRONS	both	1,258.61	TX	100%	1,258.61	2023
1760239	Measurement	ROOTS METER 3M175	378.0	230430	SHAMROCK & ENVIRONS	Jurisdictional	4,507.30	TX	100%	4,507.30	2023
1760240	Measurement	MOONEY FLOWGRID 2" ANSI	378.0	230430	LUBBOCK AREA - RURAL	Jurisdictional	25,582.60	TX	100%	25,582.60	2023
1760246	Measurement	ROOTS METER 3M175 CTR 2"	378.0	230630	LUBBOCK	Jurisdictional	2,174.13	TX	100%	2,174.13	2023
1760247	Measurement	MOONEY FLOWMAX 2" 150 CL	378.0	230630	LUBBOCK	Jurisdictional	6,596.40	TX	100%	6,596.40	2023
1760252	Measurement	SENSUS 243-RPC STANDARD	378.0	231031	MIAMI & ENVIRONS	both	1,912.50	TX	100%	1,912.50	2023
1760296	Measurement	METER REBUILDS AND	378.0	231231	DALHART AREA - RURAL	both	51,197.96	TX	100%	51,197.96	2023
1760297	Measurement	2" SICK FS600 DRU-S	378.0	231231	CANADIAN AREA TX - RURAL	both	48,197.26	TX	100%	48,197.26	2023
1760298	Measurement	KGM2005 METERS AC-250 TC	378.0	231231	LUBBOCK	Jurisdictional	47,198.75	TX	100%	47,198.75	2023
1760299	Measurement	MOONEY FLOWMAX, 2" 150 CL	378.0	231231	SAN ANTONIO AREA - RURAL	Jurisdictional	20,192.31	TX	100%	20,192.31	2023
1760300	Measurement	KGM2005 METERS, AC-250 TC	378.0	231231	LUBBOCK	Jurisdictional	17,184.30	TX	100%	17,184.30	2023
1760301	Measurement	KGM2005 METERS, AC-250 TC	378.0	231231	LUBBOCK	Jurisdictional	17,180.81	TX	100%	17,180.81	2023
1760302	Measurement	METER REPAIRS	378.0	231231	TRANS PECOS AREA - RURAL	both	37,095.67	TX	100%	37,095.67	2023
1760303	Measurement	METER REPAIRS	378.0	231231	DALHART AREA - RURAL	both	27,578.28	TX	100%	27,578.28	2023
1760304	Measurement	METER REPAIRS	378.0	231231	DALHART AREA - RURAL	both	22,945.79	TX	100%	22,945.79	2023
1760305	Measurement	METER REPAIRS	378.0	231231	DALHART AREA - RURAL	both	17,206.34	TX	100%	17,206.34	2023

1760307	Measurement	REBUILD METERS	378.0	231231	KERMIT & ENVIRONS	Jurisdictional	14,677.49	TX	100%	14,677.49	2023
1760309	Measurement	METER REPAIRS	378.0	231231	CANADIAN AREA TX - RURAL	Jurisdictional	13,234.65	TX	100%	13,234.65	2023
1760316	Measurement	SENSUS REGULATORS	378.0	231231	DALHART AREA - RURAL	both	10,599.36	TX	100%	10,599.36	2023
1760317	Measurement	SICK FS600 DRU ELECTRONIC	378.0	231231	DALHART AREA - RURAL	both	10,040.97	TX	100%	10,040.97	2023
1760318	Measurement	METER REPAIRS	378.0	231231	GUYMON AREA TX - RURAL	both	9,937.36	TX	100%	9,937.36	2023
1760319	Measurement	METER REPAIRS	378.0	231231	CANADIAN AREA TX - RURAL	Jurisdictional	9,889.31	TX	100%	9,889.31	2023
1760320	Measurement	METER REPAIRS	378.0	231231	AMARILLO AREA - RURAL	both	9,825.36	TX	100%	9,825.36	2023
1760321	Measurement	REBUILD DIAPHRAGM METERS	378.0	231231	JUNCTION & ENVIRONS	Jurisdictional	9,787.37	TX	100%	9,787.37	2023
1760322	Measurement	REBUILD DIAPHRAGM METERS	378.0	231231	SOMERSET & ENVIRONS	Jurisdictional	9,674.81	TX	100%	9,674.81	2023
1760324	Measurement	REBUILD DIAPHRAGM METERS	378.0	231231	TRANS PECOS AREA - RURAL	both	9,334.85	TX	100%	9,334.85	2023
1760325	Measurement	FS500 SICK ULTRASONIC	378.0	231231	DALHART AREA - RURAL	both	9,199.43	TX	100%	9,199.43	2023
1760326	Measurement	3M175 DRESSER ROTARY	378.0	231231	DALHART AREA - RURAL	both	8,963.10	TX	100%	8,963.10	2023
1760331	Measurement	METER REPAIRS	378.0	231231	VAN HORN & ENVIRONS	Jurisdictional	7,639.23	TX	100%	7,639.23	2023
1760332	Measurement	ERG-5006-001U AMERICAN	378.0	231231	LUBBOCK	Jurisdictional	7,532.77	TX	100%	7,532.77	2023
1760336	Measurement	METER REPAIRS	378.0	231231	KERMIT & ENVIRONS	Jurisdictional	6,254.74	TX	100%	6,254.74	2023
1760346	Measurement	KGM2011 METERS	378.0	231231	KERMIT & ENVIRONS	Jurisdictional	3,009.67	TX	100%	3,009.67	2023
1760347	Measurement	METER REPAIRS	378.0	231231	STRATFORD & ENVIRONS	both	4,802.50	TX	100%	4,802.50	2023
1760348	Measurement	METER REPAIRS	378.0	231231	STRATFORD & ENVIRONS	both	4,121.47	TX	100%	4,121.47	2023
1760350	Measurement	METER REPAIRS	378.0	231231	GROOM & ENVIRONS	both	3,661.03	TX	100%	3,661.03	2023
1760352	Measurement	METER SET	378.0	231231	LUBBOCK	Jurisdictional	8,521.01	TX	100%	8,521.01	2023
1760354	Measurement	NCG HYDRO CONVERTERS	378.0	231231	AMARILLO	Both	10,260.15	TX	100%	10,260.15	2023
1760356	Measurement	METER REPAIRS	378.0	231231	LUBBOCK AREA - RURAL	both	24,683.97	TX	100%	24,683.97	2023
1760357	Measurement	REBUILD DIAPHRAGM METERS	378.0	231231	TRANS PECOS AREA - RURAL	both	9,636.68	TX	100%	9,636.68	2023
1760374	Measurement	PO 28165 2 VALVES GREEN	378.0	231231	DALHART AREA - RURAL	both	7,934.50	TX	100%	7,934.50	2023
1760392	Measurement	PO 28529 SEABOARD	378.0	231231	DALHART AREA - RURAL	Non-Jurisdictional	931.23	TX	100%	931.23	2023
1760413	Measurement	METER REPAIRS	378.0	231231	GROOM & ENVIRONS	both	10,795.53	TX	100%	10,795.53	2023
1760414	Measurement	REGULATOR	378.0	231231	HIGGINS & ENVIRONS	both	2,079.79	TX	100%	2,079.79	2023
1760415	Measurement	METER REPAIRS	378.0	231231	DALHART AREA - RURAL	both	16,270.87	TX	100%	16,270.87	2023
1760416	Measurement	METER ROTARY 5.5M 3 ANSI	378.0	231231	SOMERSET & ENVIRONS	Jurisdictional	2,374.40	TX	100%	2,374.40	2023
1760417	Measurement	METER REBUILDS	378.0	231231	WHEELER TX & ENVIRONS	Jurisdictional	3,155.22	TX	100%	3,155.22	2023
1760418	Measurement	METER REBUILDS	378.0	231231	SHAMROCK & ENVIRONS	Jurisdictional	3,155.23	TX	100%	3,155.23	2023
1760419	Measurement	METER RUBILDS	378.0	231231	DALHART AREA - RURAL	both	46,016.02	TX	100%	46,016.02	2023
1760420	Measurement	METER REBUILDS	378.0	231231	DALHART AREA - RURAL	both	45,517.51	TX	100%	45,517.51	2023
1760421	Measurement	COMPOSIT CONTROL LOOP W/	378.0	231231	CANADIAN & ENVIRONS	Jurisdictional	2,799.63	TX	100%	2,799.63	2023
1760424	Measurement	ROTARY METERS	378.0	231231	SOMERSET & ENVIRONS	Jurisdictional	12,968.36	TX	100%	12,968.36	2023
1760521	Measurement	SICK FS500 PTZ UPGRADE	378.0	230831	BALMORHEA & ENVIRONS	both	2,360.13	TX	100%	2,360.13	2023
1760522	Measurement	SICK FS500 PTZ UPGRADE	378.0	230831	LUBBOCK AREA - RURAL	Jurisdictional	2,327.54	TX	100%	2,327.54	2023
2060241	Field Equipment	SENSIT GOLD G2 EX/TC/CO	387.0	230430	CANADIAN & ENVIRONS	both	2,409.80	TX	100%	2,409.80	2023
2160225	Field Equipment	PROCESSOR EF ELEKTRA	387.0	230131	SHAMROCK & ENVIRONS	both	2,867.12	TX	100%	2,867.12	2023
2160242	Field Equipment	MEASURING INSTRUMENT TW-6	387.0	230430	CANADIAN & ENVIRONS	both	1,241.43	TX	100%	1,241.43	2023
7060333	Buildings	REMOVE AND REPAIR DAMAGED ROOF	390.0	231231	LUBBOCK AREA - RURAL	both	7,472.50	TX	100%	7,472.50	2023
6560342	Office Equipment	3.5 TN 16 SEER CARRIER AC	391.0	231231	BEAVER OK	Out of State	5,450.00	OK	0%	-	2023
6360244	Equipment	2017 POLARIS RANGER	392.0	230430	BEAVER OK	Out of State	9,500.00	OK	0%	-	2023
5460245	Field Equipment	2019 CAT 303.5E COMPACT	394.0	230531	GROOM & ENVIRONS	Both	43,300.00	TX	100%	43,300.00	2023
5906535	Field Equipment	OD2, COMPLETE, METHANE	394.0	230930	SAN ANTONIO AREA - RURAL	Jurisdictional	5,710.46	TX	100%	5,710.46	2023
5906538	Field Equipment	DRONE BUNDLE, DJI MINI 3	394.0	231031	LUBBOCK	Jurisdictional	1,059.77	TX	100%	1,059.77	2023
5960227	Field Equipment	LOCATOR SNAPTRACK KIT 10	394.0	230131	LUBBOCK AREA - RURAL	Jurisdictional	5,452.48	TX	100%	5,452.48	2023
5960231	Field Equipment	LOCATOR STICK V3 3 WATT	394.0	230228	TRANS PECOS AREA - RURAL	Jurisdictional	1,895.14	TX	100%	1,895.14	2023
5960250	Field Equipment	LOCATOR 8869 PLS V3	394.0	230731	SOMERSET & ENVIRONS	both	757.75	TX	100%	757.75	2023
5960251	Field Equipment	SENSIT GOLD G2 TX/TC	394.0	231031	SOMERSET & ENVIRONS	both	2,327.91	TX	100%	2,327.91	2023
5960295	Field Equipment	6000 WATT GENERATOR	394.0	231231	KERMIT & ENVIRONS	Jurisdictional	865.99	TX	100%	865.99	2023
5960334	Field Equipment	LOCATOR PATHFINDER	394.0	231231	JUNCTION & ENVIRONS	both	6,551.54	TX	100%	6,551.54	2023
5960335	Field Equipment	PIG LOCATOR	394.0	231231	CANADIAN AREA TX - RURAL	Both	6,299.64	TX	100%	6,299.64	2023
5960343	Field Equipment	FG HP MAGNESIUM ANODE PKG	394.0	231231	DALHART AREA - RURAL	Both	5,322.44	TX	100%	5,322.44	2023
5960411	Field Equipment	2 SQUEEZE TOOLS	394.0	231231	AMARILLO AREA - RURAL	Both	1,939.99	TX	100%	1,939.99	2023
5660253	Comminication Equip	RADIOS, FGR2-IOS-C-U	397.0	231130	HOME OFFICE G&A	Both	19,311.80	CORP	94.25%	18,201.37	2023
3560118	System Integrity	KEROTEST INSULATORS	367.0	220630	CANADIAN AREA TX - RURAL	Jurisdictional	4,505.18	TX	100.00%	4,505.18	2022
3560188	System Integrity	PO 28261 4" REPL @ 6H-44	367.0	221231	SAN ANTONIO AREA - RURAL	Jurisdictional	250,537.30	TX	100.00%	250,537.30	2022
3560189	System Integrity	PO 28382 REPL 8500' 6H-10	367.0	221231	SAN ANTONIO AREA - RURAL	Jurisdictional	662,638.90	TX	100.00%	662,638.90	2022
3660134	Measurement	PERRTON HCA VALVES	369.0	220731	CANADIAN AREA TX - RURAL	Jurisdictional	31,290.00	TX	100.00%	31,290.00	2022
3660159	Measurement	3 ISOLATION VALVES	369.0	221231	CANADIAN AREA TX - RURAL	Jurisdictional	5,095.82	TX	100.00%	5,095.82	2022
3660191	Measurement	PO 28253 4" RISER @ 6H-44	369.0	221231	SAN ANTONIO AREA - RURAL	Jurisdictional	16,623.51	TX	100.00%	16,623.51	2022
3960144	Measurement	MEASURING INSTRUMENT	369.0	220930	CANADIAN AREA TX - RURAL	Jurisdictional	1,103.85	TX	100.00%	1,103.85	2022
1660090	System Integrity	PO 24272 HONDO UPGRADE	376.0	220531	SAN ANTONIO AREA - RURAL	Jurisdictional	4,441.61	TX	100.00%	4,441.61	2022
1660091	System Growth	PO 25631 BLACK MOUNTAIN	376.0	220531	SAN ANTONIO AREA - RURAL	Both	127,195.97	TX	100.00%	127,195.97	2022
1660092	System Growth	PO 25773 HATTON PAHSE 3	376.0	220531	LUBBOCK	Jurisdictional	69,335.85	TX	100.00%	69,335.85	2022
1660093	System Growth	PO 26050 SOUTH COOPER	376.0	220531	LUBBOCK	Jurisdictional	926,831.75	TX	100.00%	926,831.75	2022
1660094	System Growth	PO 26264 UCA COMMERCIAL	376.0	220531	LUBBOCK	Jurisdictional	12,751.27	TX	100.00%	12,751.27	2022
1660095	System Growth	PO 26341 BIGGIN HILL	376.0	220531	LUBBOCK AREA - RURAL	Jurisdictional	5,777.60	TX	100.00%	5,777.60	2022
1660096	System Growth	PO 26481 MAGNOLISA ESTATE	376.0	220531	LUBBOCK	Jurisdictional	54,410.38	TX	100.00%	54,410.38	2022
1660097	System Growth	PO 26618 SOUTH FORK	376.0	220531	LUBBOCK AREA - RURAL	Jurisdictional	63,386.40	TX	100.00%	63,386.40	2022
1660098	System Growth	PO 27676 MAGNOLIA ESTATES	376.0	220531	LUBBOCK	Jurisdictional	52,695.35	TX	100.00%	52,695.35	2022
1660099	System Growth	PO 27707 KUBIE ESTATES	376.0	220531	LUBBOCK	Jurisdictional	112,141.00	TX	100.00%	112,141.00	2022
1660100	System Growth	PO 27708 SUNDANCE ESTATE	376.0	220531	LUBBOCK	Jurisdictional	79,633.93	TX	100.00%	79,633.93	2022
1660101	System Growth	PO 27709 SOUTHERN RANCH	376.0	220531	LUBBOCK AREA - RURAL	Jurisdictional	170,851.54	TX	100.00%	170,851.54	2022
1660102	System Growth	PO 27711 VERRADO ESTATES	376.0	220531	LUBBOCK	Jurisdictional	93,342.73	TX	100.00%	93,342.73	2022
1660103	System Growth	PO 27712 EASTWICK @	376.0	220531	LUBBOCK	Jurisdictional	55,206.31	TX	100.00%	55,206.31	2022
1660104	System Growth	PO 27864 BETENBOUGH	376.0	220531	LUBBOCK	Jurisdictional	49,966.75	TX	100.00%	49,966.75	2022
1660105	System Growth	PO 27931 RE-ROUTE P/L	376.0	220531	LUBBOCK	Jurisdictional	34,180.00	TX	100.00%	34,180.00	2022
1660106	System Growth	PO 28047 HATTON PLACE	376.0	220531	LUBBOCK	Jurisdictional	112,816.65	TX	100.00%	112,816.65	2022

1660107	System Growth	PO 28048 HATTON PLACE	376.0	220531	LUBBOCK	Jurisdictional	41,468.64	TX	100.00%	41,468.64	2022
1660108	System Growth	PO 28111 BETENBOUGH	376.0	220531	LUBBOCK AREA - RURAL	Jurisdictional	109,420.83	TX	100.00%	109,420.83	2022
160218	DIMP	PO 90311 2022 DIMP BOISE	376.0	221231	BOISE CITY OK	Out of State	699,915.74	OK	0.00%	-	2022
160219	DIMP	PO 90312 2022 DIMP BEAVER	376.0	221231	BEAVER OK	Out of State	544,843.15	OK	0.00%	-	2022
1660162	System Growth	PO 28178 BALMORHEA SCHOOL	376.0	221231	BALMORHEA & ENVIRONS	Jurisdictional	51,606.49	TX	100.00%	51,606.49	2022
1660163	System Growth	PO 28363 BIAD REG SET &	376.0	221231	TRANS PECOS AREA - RURAL	Non-Jurisdictional	69,521.78	TX	100.00%	69,521.78	2022
1660164	System Growth	PO 27710 VINTAGE OFFICE	376.0	221231	LUBBOCK	Jurisdictional	16,678.11	TX	100.00%	16,678.11	2022
1660165	System Growth	PO 27908 SOUTH FORK PHASE	376.0	221231	LUBBOCK	Jurisdictional	60,310.37	TX	100.00%	60,310.37	2022
1660166	System Growth	PO 28362 UMC HOSPITAL	376.0	221231	LUBBOCK	Jurisdictional	11,124.24	TX	100.00%	11,124.24	2022
1660167	System Growth	PO 28423 SPANISH BIT	376.0	221231	LUBBOCK	Jurisdictional	80,907.63	TX	100.00%	80,907.63	2022
1660168	System Growth	PO 28058 ALGRANO PEANUT	376.0	221231	LUBBOCK AREA - RURAL	Non-Jurisdictional	42,295.97	TX	100.00%	42,295.97	2022
1660169	System Growth	PO 28080 BENNETT/APEX EXT	376.0	221231	LUBBOCK AREA - RURAL	Jurisdictional	13,927.74	TX	100.00%	13,927.74	2022
1660170	System Growth	PO 28250 WOODROW ROAD	376.0	221231	LUBBOCK AREA - RURAL	Jurisdictional	9,703.00	TX	100.00%	9,703.00	2022
1660171	System Growth	PO 28273 SYSTEM 213 & 200	376.0	221231	LUBBOCK AREA - RURAL	Jurisdictional	130,811.75	TX	100.00%	130,811.75	2022
1660172	System Growth	PO 27756 PANCOST	376.0	221231	AMARILLO	Jurisdictional	32,867.39	TX	100.00%	32,867.39	2022
1660173	System Growth	PO 27825 OSAGE BUSINESS	376.0	221231	AMARILLO	Jurisdictional	34,307.16	TX	100.00%	34,307.16	2022
1660174	System Growth	PO 28201 OVERGRAW LINE	376.0	221231	AMARILLO	Jurisdictional	4,769.78	TX	100.00%	4,769.78	2022
1660175	System Growth	PO 28325 HIGHLAND SPRINGS	376.0	221231	AMARILLO	Jurisdictional	194,727.28	TX	100.00%	194,727.28	2022
1660176	System Growth	PO 28364 STONE CROSSING	376.0	221231	AMARILLO	Jurisdictional	128,595.57	TX	100.00%	128,595.57	2022
1660177	System Growth	PO 27937 FULL CIRCLE	376.0	221231	DALHART AREA - RURAL	Non-Jurisdictional	427,448.87	TX	100.00%	427,448.87	2022
1660178	System Growth	PO 28349 MACKEY RD 6"	376.0	221231	DALHART AREA - RURAL	Jurisdictional	43,397.43	TX	100.00%	43,397.43	2022
1660179	System Growth	PO 28389 GREENGASCO GAS	376.0	221231	DALHART AREA - RURAL	Non-Jurisdictional	724,787.91	TX	100.00%	724,787.91	2022
1660180	System Growth	PO 28467 MCWILLIAMS EXT	376.0	221231	DALHART AREA - RURAL	Jurisdictional	13,364.20	TX	100.00%	13,364.20	2022
1660181	System Growth	PO 28518 WHISKEY RIVER	376.0	221231	DALHART AREA - RURAL	Jurisdictional	2,662.00	TX	100.00%	2,662.00	2022
1660182	System Growth	PO 27632 EL INDO LOOP	376.0	221231	SAN ANTONIO AREA - RURAL	Jurisdictional	640,529.22	TX	100.00%	640,529.22	2022
1660183	System Growth	PO 28406 6K 10" MAVERICK	376.0	221231	SAN ANTONIO AREA - RURAL	Jurisdictional	80,258.40	TX	100.00%	80,258.40	2022
1660184	System Growth	PO 28524 BLACKBRUSH WELL	376.0	221231	SAN ANTONIO AREA - RURAL	Jurisdictional	20,630.88	TX	100.00%	20,630.88	2022
1660193	DIMP	PO 90274 2022 DIMP KERMIT	376.0	221231	KERMIT & ENVIRIONS	Jurisdictional	1,486,298.59	TX	100.00%	1,486,298.59	2022
1660194	DIMP	PO 90277 2022 DIMP VAN	376.0	221231	VAN HORN & ENVIRONS	Jurisdictional	106,808.83	TX	100.00%	106,808.83	2022
1660195	DIMP	PO 90278 2022 DIMP TRANS	376.0	221231	TRANS PECOS AREA - RURAL	Jurisdictional	3,689.97	TX	100.00%	3,689.97	2022
1660196	DIMP	PO 90281 2022 DIMP	376.0	221231	JUNCTION & ENVIRONS	Jurisdictional	247,363.77	TX	100.00%	247,363.77	2022
1660197	DIMP	PO 90282 2022 DIMP MENARD	376.0	221231	MENARD & ENVIRONS	Jurisdictional	74,837.70	TX	100.00%	74,837.70	2022
1660198	DIMP	PO 90283 2022 DIMP SONORA	376.0	221231	SONORA & ENVIRONS	Jurisdictional	78,027.90	TX	100.00%	78,027.90	2022
1660199	DIMP	PO 90284 2022 DIMP EDEN	376.0	221231	EDEN & ENVIRONS	Jurisdictional	766,008.03	TX	100.00%	766,008.03	2022
1660200	DIMP	PO 90285 2022 DIMP	376.0	221231	CHRISTOVAL ENVIRONS	Jurisdictional	7,085.64	TX	100.00%	7,085.64	2022
1660201	DIMP	PO 90286 2022 DIMP PAINT	376.0	221231	PAINT ROCK & ENVIRONS	Jurisdictional	43,515.75	TX	100.00%	43,515.75	2022
1660202	DIMP	PO 90288 2022 DIMP	376.0	221231	CANADIAN & ENVIRONS	Jurisdictional	812,925.15	TX	100.00%	812,925.15	2022
1660203	DIMP	PO 90289 2022 DIMP	376.0	221231	WHEELER TX & ENVIRONS	Jurisdictional	468,672.74	TX	100.00%	468,672.74	2022
1660204	DIMP	PO 90290 2022 DIMP	376.0	221231	SHAMROCK & ENVIRONS	Jurisdictional	809,323.49	TX	100.00%	809,323.49	2022
1660205	DIMP	PO 90293 2022 DIMP	376.0	221231	FOLLETT & ENVIRONS	Jurisdictional	23,670.65	TX	100.00%	23,670.65	2022
1660206	DIMP	PO 90294 2022 DIMP MIAMI	376.0	221231	MIAMI & ENVIRONS	Jurisdictional	902,486.02	TX	100.00%	902,486.02	2022
1660207	DIMP	PO 90296 2022 DIMP	376.0	221231	CANADIAN AREA TX - RURAL	Jurisdictional	66,928.36	TX	100.00%	66,928.36	2022
1660208	DIMP	PO 90297 2022 DIMP GROOM	376.0	221231	GROOM & ENVIRONS	Jurisdictional	54,938.35	TX	100.00%	54,938.35	2022
1660209	DIMP	PO 90298 2022 DIMP	376.0	221231	FARWELL & ENVIRONS	Jurisdictional	324,884.68	TX	100.00%	324,884.68	2022
1660210	DIMP	PO 90299 2022 DIMP CLAUDE	376.0	221231	CLAUDE & ENVIRONS	Jurisdictional	276,664.22	TX	100.00%	276,664.22	2022
1660211	DIMP	PO 90300 2022 DIMP WHITE	376.0	221231	WHITE DEER & ENVIRONS	Jurisdictional	48,387.96	TX	100.00%	48,387.96	2022
1660212	DIMP	PO 90301 2022 DIMP	376.0	221231	AMARILLO	Jurisdictional	44,570.26	TX	100.00%	44,570.26	2022
1660213	DIMP	PO 90305 2022 DIMP	376.0	221231	TEXLINE & ENVIRONS	Jurisdictional	165,640.32	TX	100.00%	165,640.32	2022
1660214	DIMP	PO 90306 2022 DIMP	376.0	221231	DALHART AREA - RURAL	Jurisdictional	17,502.27	TX	100.00%	17,502.27	2022
1660215	DIMP	PO 90307 2022 DIMP	376.0	221231	STRATFORD & ENVIRONS	Jurisdictional	53,524.84	TX	100.00%	53,524.84	2022
1660216	DIMP	PO 90309 2022 DIMP	376.0	221231	TEXHOMA OK	Out of State	243,372.82	OK	0.00%	-	2022
1660217	DIMP	PO 90310 2022 DIMP GUYMON	376.0	221231	BOISE CITY OK	Out of State	24,159.75	OK	0.00%	-	2022
1660220	DIMP	PO 90313 2022 DIMP	376.0	221231	SOMERSET & ENVIRONS	Jurisdictional	319,561.01	TX	100.00%	319,561.01	2022
1660221	DIMP	PO 90314 2022 DIMP DEVINE	376.0	221231	DEVINE & ENVIRONS	Jurisdictional	17,955.64	TX	100.00%	17,955.64	2022
1660222	DIMP	PO 90315 2022 DIMP LA	376.0	221231	LA PRYOR	Jurisdictional	517,928.21	TX	100.00%	517,928.21	2022
1660223	DIMP	PO 90316 2022 DIMP SAN	376.0	221231	NATALIA & ENVIRONS	Jurisdictional	285,338.79	TX	100.00%	285,338.79	2022
1660224	DIMP	PO 90317 2022 DIMP SAN	376.0	221231	SAN ANTONIO AREA - RURAL	Jurisdictional	70,902.55	TX	100.00%	70,902.55	2022
1760070	Measurement	ROOTS METER 2M175	378.0	220131	VAN HORN & ENVIRONS	Jurisdictional	3,687.48	TX	100.00%	3,687.48	2022
1760123	Measurement	10" X 350' DEEP WELLS	378.0	220731	VAN HORN & ENVIRONS	Jurisdictional	49,449.69	TX	100.00%	49,449.69	2022
1760124	Measurement	10" X 350' DEEP WELLS	378.0	220731	VAN HORN & ENVIRONS	Jurisdictional	45,173.12	TX	100.00%	45,173.12	2022
1760125	Measurement	10'X 350' DEEP WELLS	378.0	220731	VAN HORN & ENVIRONS	Jurisdictional	50,512.19	TX	100.00%	50,512.19	2022
1760185	Measurement	PO 28235 REG REPL @ VAN	378.0	221231	VAN HORN & ENVIRONS	Jurisdictional	26,653.92	TX	100.00%	26,653.92	2022
1760074	Measurement	FS500 SICK ULTRASONIC	378.0	220131	TRANS PECOS AREA - RURAL	Jurisdictional	6,159.66	TX	100.00%	6,159.66	2022
1760075	Measurement	DRESSER METER	378.0	220131	TRANS PECOS AREA - RURAL	Jurisdictional	2,050.43	TX	100.00%	2,050.43	2022
1760109	Measurement	10" X 260' DEEP WEELS	378.0	220531	TRANS PECOS AREA - RURAL	Jurisdictional	43,843.94	TX	100.00%	43,843.94	2022
1760122	Measurement	10" X 350' DEEP WELLS	378.0	220731	TRANS PECOS AREA - RURAL	Jurisdictional	47,085.62	TX	100.00%	47,085.62	2022
1760129	Measurement	ROOTS METER 2M175 CTR	378.0	220731	TRANS PECOS AREA - RURAL	Jurisdictional	1,703.44	TX	100.00%	1,703.44	2022
1760130	Measurement	DRESSER #400 IMC/W2 PTZ	378.0	220731	TRANS PECOS AREA - RURAL	Jurisdictional	1,965.63	TX	100.00%	1,965.63	2022
1760146	Measurement	KGM0011 REGULATOR 1813B	378.0	221031	TRANS PECOS AREA - RURAL	Jurisdictional	826.64	TX	100.00%	826.64	2022
1760147	Measurement	MOONEY SERIES 20 PILOT	378.0	221031	TRANS PECOS AREA - RURAL	Jurisdictional	960.04	TX	100.00%	960.04	2022
1760071	Measurement	REBUILT 7M175	378.0	220131	LUBBOCK AREA - RURAL	Jurisdictional	1,768.01	TX	100.00%	1,768.01	2022
1760072	Measurement	ROOTS METER 7M175	378.0	220131	LUBBOCK AREA - RURAL	Jurisdictional	3,423.03	TX	100.00%	3,423.03	2022
1760073	Measurement	REBUILT 11M175 METER	378.0	220131	LUBBOCK AREA - RURAL	Jurisdictional	2,117.16	TX	100.00%	2,117.16	2022
1760110	Measurement	METER REBUILT ROTART	378.0	220531	LUBBOCK AREA - RURAL	Jurisdictional	3,182.49	TX	100.00%	3,182.49	2022
1760141	Measurement	DRESSER #400 IMC/W2 PTZ,	378.0	220831	CANADIAN AREA TX - RURAL	Jurisdictional	2,030.32	TX	100.00%	2,030.32	2022
1760083	Measurement	EC350 ELECTRONIC VOLUME	378.0	220331	DALHART AREA - RURAL	Jurisdictional	7,676.83	TX	100.00%	7,676.83	2022
1760084	Measurement	SENSUS REGULATORS 1813C	378.0	220331	DALHART AREA - RURAL	Jurisdictional	1,628.95	TX	100.00%	1,628.95	2022
1760086	Measurement	RECTIFIER GROUND BEDS	378.0	220430	DALHART AREA - RURAL	Jurisdictional	44,225.44	TX	100.00%	44,225.44	2022
1760126	Measurement	10" X 350' DEEP WELLS	378.0	220731	DALHART AREA - RURAL	Jurisdictional	44,315.54	TX	100.00%	44,315.54	2022
1760127	Measurement	10" X 350' DEEP WELLS	378.0	220731	DALHART AREA - RURAL	Jurisdictional	44,247.96	TX	100.00%	44,247.96	2022

1760128	Measurement	10" X 350' DEEP WELLS	378.0	220731	DALHART AREA - RURAL	Jurisdictional	44,225.44	TX	100.00%	44,225.44	2022
1760131	Measurement	GUAGE PRESSURE TRANSDUCER	378.0	220731	DALHART AREA - RURAL	Jurisdictional	10,167.44	TX	100.00%	10,167.44	2022
1760132	Measurement	3M175 DRESSER ROTARY	378.0	220731	DALHART AREA - RURAL	Jurisdictional	10,456.96	TX	100.00%	10,456.96	2022
1760186	Measurement	PO 28219 10" BLOCK VAVLE	378.0	221231	DALHART AREA - RURAL	Jurisdictional	48,093.35	TX	100.00%	48,093.35	2022
1760117	Measurement	REGULATOR, P627 2" 150#	378.0	220630	SOMERSET & ENVIRONS	Jurisdictional	7,036.52	TX	100.00%	7,036.52	2022
1760133	Measurement	REBUILT R1600 HP METER	378.0	220731	SAN ANTONIO AREA - RURAL	Jurisdictional	3,342.61	TX	100.00%	3,342.61	2022
1760187	Measurement	PO 28241 DEEPWELL & RECTIFIER	378.0	221231	SAN ANTONIO AREA - RURAL	Jurisdictional	51,653.98	TX	100.00%	51,653.98	2022
260111	Measurement	10' X 350' DEEP WELLS & Rectifier	378.0	220531	TEXHOMA OK	Out of State	42,457.77	OK	0.00%	-	2022
260112	Measurement	10' X 350' DEEP WELLS & Rectifier	378.0	220531	TEXHOMA OK	Out of State	42,457.77	OK	0.00%	-	2022
2160148	Field Equipment	CAL KIT 4 GAS/TC/ MODEL H	387.0	221031	LUBBOCK AREA - RURAL	Both	1,270.60	TX	100.00%	1,270.60	2022
2160087	Field Equipment	RMLD-CS MODEL W/ 10.8V	387.0	220430	CANADIAN & ENVIRONS	Both	16,676.58	TX	100.00%	16,676.58	2022
560149	Field Equipment	PROCESSOR EF ELEKTRA	387.0	221031	BEAVER OK	Out of State	2,908.67	OK	0.00%	-	2022
7060116	Buildings	AMARILLO OFFICE	390.0	220531	AMARILLO	Both	23,100.00	TX	100.00%	23,100.00	2022
7060089	Buildings	PO 21976 UPDATE TO SOMERSET WAREHOU	390.0	220531	SOMERSET & ENVIRONS	Both	15,980.01	TX	100.00%	15,980.01	2022
5760121	Office Equipment	PRECISION 5820 TOWER	391.0	220630	AMARILLO	Both	1,982.43	TX	100.00%	1,982.43	2022
5760137	Office Equipment	INTEL AS210 WLAN DRIVER	391.0	220731	AMARILLO	Both	2,309.27	TX	100.00%	2,309.27	2022
6560143	Office Equipment	3 TON 16 SEER CARRIER AC	391.0	220831	BEAVER OK	Out of State	6,675.00	OK	0.00%	-	2022
5160135	Equipment	UNIT 40022 2022 SILVERADO	392.0	220731	LUBBOCK	Both	45,288.52	TX	100.00%	45,288.52	2022
5160114	Equipment	UNIT 40012 2022 GMC	392.0	220531	JUNCTION & ENVIRONS	Both	47,947.93	TX	100.00%	47,947.93	2022
5160077	Equipment	UNIT 40007 2022 SILVERADO	392.0	220131	DALHART AREA - RURAL	Both	39,888.00	TX	100.00%	39,888.00	2022
6260081	Equipment	UNIT 40009 2022 SILVERADO	392.0	220228	BEAVER OK	Out of State	40,329.00	OK	0.00%	-	2022
6260082	Equipment	UNIT 40010 2022 SILVERADO	392.0	220228	BEAVER OK	Out of State	39,888.00	OK	0.00%	-	2022
5960152	Field Equipment	PROCESSOR EF ELEKTRA	394.0	221031	KERMIT & ENVIRIONS	Both	2,885.76	TX	100.00%	2,885.76	2022
5960079	Field Equipment	ELEKTRA LIGHT 110VAC	394.0	220228	TRANS PECOS AREA - RURAL	Both	2,678.11	TX	100.00%	2,678.11	2022
5960088	Field Equipment	RECTIFIER ASAI 50-50	394.0	220430	TRANS PECOS AREA - RURAL	Both	4,659.85	TX	100.00%	4,659.85	2022
5960155	Field Equipment	GROW AMR DRIVE BY BUNDLE	394.0	221130	LUBBOCK AREA - RURAL	Both	16,995.25	TX	100.00%	16,995.25	2022
5960115	Field Equipment	LOCATOR PATHFINDER	394.0	220531	JUNCTION & ENVIRONS	Both	5,467.56	TX	100.00%	5,467.56	2022
5960154	Field Equipment	2 TW-6 LINE LOCATORS	394.0	221130	CANADIAN & ENVIRONS	Both	2,130.38	TX	100.00%	2,130.38	2022
5960160	Field Equipment	DURO MAX PORTABLE	394.0	221231	CANADIAN & ENVIRONS	Both	1,970.15	TX	100.00%	1,970.15	2022
5960153	Field Equipment	PROCESSOR EF ELEKTRA	394.0	221031	GROOM & ENVIRONS	Both	5,738.00	TX	100.00%	5,738.00	2022
5960138	Field Equipment	SENSIT GOLD G2 TC EX/TC/	394.0	220731	DALHART AREA - RURAL	Both	2,759.91	TX	100.00%	2,759.91	2022
5960150	Field Equipment	KINGTOOL MODEL 2-B 300#	394.0	221031	DALHART AREA - RURAL	Both	3,093.57	TX	100.00%	3,093.57	2022
5960151	Field Equipment	SENSIT GOLD G2 TC EX/TC/	394.0	221031	DALHART AREA - RURAL	Both	2,924.22	TX	100.00%	2,924.22	2022
5960161	Field Equipment	KINGTOOL MODEL 3-B 500#	394.0	221231	DALHART AREA - RURAL	Both	4,037.51	TX	100.00%	4,037.51	2022
5960139	Field Equipment	RYCOM LOCATOR SNAPTRACK	394.0	220731	SOMERSET & ENVIRONS	Both	4,600.64	TX	100.00%	4,600.64	2022
5960085	Field Equipment	RMLD-CS LEAK DETECTION	394.0	220331	SAN ANTONIO AREA - RURAL	Both	16,674.55	TX	100.00%	16,674.55	2022
6660089	Field Equipment	PROCESSOR EF ELEKTRA	394.0	220430	TEXHOMA OK	Out of State	2,728.07	OK	0.00%	-	2022
6660078	Field Equipment	SENSIT PMD W/GPS	394.0	220228	BEAVER OK	Out of State	11,770.32	OK	0.00%	-	2022
5660120	Comminication Equip	ZULTYS MX-SE PHONE SYSTEM	397.0	220630	STRATFORD & ENVIRONS	Both	14,328.83	TX	100.00%	14,328.83	2022
6060140	Equipment	2022 POLARIS RANGER 500	398.0	220731	CANADIAN AREA TX - RURAL	Both	13,200.56	TX	100.00%	13,200.56	2022
6060192	Equipment	DEEPWELL RECTIFIER	398.0	221231	SAN ANTONIO AREA - RURAL	Both	56,570.54	TX	100.00%	56,570.54	2022
5160076	Equipment	UNIT 40005 2022 SILVERADO	392.0	220131	HOME OFFICE G&A	Both	53,640.00	CORP	94.25%	50,555.70	2022
5160113	Equipment	UNIT 40011 2022 SILVERADO	392.0	220531	HOME OFFICE G&A	Both	60,159.03	CORP	94.25%	56,699.89	2022
5160119	Equipment	UNIT 40018 2022 GMC	392.0	220630	HOME OFFICE G&A	Both	51,470.94	CORP	94.25%	48,511.36	2022
5160136	Equipment	UNIT 40022 2022 SIERRA	392.0	220731	HOME OFFICE G&A	Both	51,699.69	CORP	94.25%	48,726.96	2022
5160142	Equipment	2022 CHEVY SILVERADO	392.0	220831	HOME OFFICE G&A	Both	50,320.69	CORP	94.25%	47,427.25	2022
3569973	System Integrity	REPLACED 400 FT OF 6"	367.0	210630	CANADIAN AREA TX - RURAL	Jurisdictional	14,575.00	TX	100.00%	14,575.00	2021
3659982	Measurement	FM-1T-50 MOONEY FLOWMAX	369.0	210831	SAN ANTONIO AREA - RURAL	Jurisdictional	10,423.79	TX	100.00%	10,423.79	2021
3660038	Measurement	PO 28007 REGULATOR	369.0	211231	SAN ANTONIO AREA - RURAL	Jurisdictional	3,448.57	TX	100.00%	3,448.57	2021
3569948	Measurement	ROOTS METER, 2M175 CD 2"	369.1	210430	SAN ANTONIO AREA - RURAL	Jurisdictional	3,827.50	TX	100.00%	3,827.50	2021
1669931	System Integrity	DEEPWELL GROUNDBED AT	376.0	210131	SAN ANTONIO AREA - RURAL	Jurisdictional	31,302.14	TX	100.00%	31,302.14	2021
1669952	System Growth	PO 25774 SOUTH FORK PHASE	376.0	210531	LUBBOCK AREA - RURAL	Jurisdictional	47,708.27	TX	100.00%	47,708.27	2021
1669953	System Growth	PO 25775 MURRY UPLAND	376.0	210531	LUBBOCK AREA - RURAL	Jurisdictional	80,753.64	TX	100.00%	80,753.64	2021
1669954	System Growth	PO 25936 MAGNOLIA ESTATES	376.0	210531	LUBBOCK	Jurisdictional	118,606.35	TX	100.00%	118,606.35	2021
1669955	System Growth	PO 25972 STONEWOOD	376.0	210531	LUBBOCK	Jurisdictional	24,557.74	TX	100.00%	24,557.74	2021
1669956	System Growth	PO 26051 WESTMONT PROJECT	376.0	210531	LUBBOCK AREA - RURAL	Jurisdictional	232,171.14	TX	100.00%	232,171.14	2021
1669957	System Growth	PO 26139 VETERANS	376.0	210531	LUBBOCK	Jurisdictional	10,911.60	TX	100.00%	10,911.60	2021
1669958	System Growth	PO 26305 COLLIER	376.0	210531	LUBBOCK	Jurisdictional	2,163.14	TX	100.00%	2,163.14	2021
1669959	System Growth	PO 26323 MEMPHIS HOUSE	376.0	210531	LUBBOCK	Jurisdictional	22,574.74	TX	100.00%	22,574.74	2021
1669960	System Growth	PO 26480 HATTON PLACE NEW	376.0	210531	LUBBOCK AREA - RURAL	Jurisdictional	168,122.82	TX	100.00%	168,122.82	2021
1669961	System Growth	PO 26617 FOUNTAIN HILL	376.0	210531	LUBBOCK AREA - RURAL	Jurisdictional	35,211.62	TX	100.00%	35,211.62	2021
1669962	System Growth	PO 26846 PAINTED PRARIE	376.0	210531	LUBBOCK	Jurisdictional	276,172.13	TX	100.00%	276,172.13	2021
1669963	System Growth	PO 27023 BAILEY BOILER	376.0	210531	LUBBOCK	Jurisdictional	2,917.08	TX	100.00%	2,917.08	2021
1669964	System Growth	PO 27024 STONEWOOD	376.0	210531	LUBBOCK	Jurisdictional	5,909.87	TX	100.00%	5,909.87	2021
1669965	System Growth	PO 27223 ONEOK SUPPLY	376.0	210531	LUBBOCK	Jurisdictional	755,968.14	TX	100.00%	755,968.14	2021
1669966	System Growth	PO 27385 ROPESVILLE	376.0	210531	LUBBOCK	Jurisdictional	190,103.95	TX	100.00%	190,103.95	2021
1669967	System Growth	PO 27409 PRIMROSE SCHOOL	376.0	210531	LUBBOCK	Jurisdictional	8,989.01	TX	100.00%	8,989.01	2021
269971	System Growth	OKLAHOMA DRY TRAILS	376.0	210531	TEXHOMA OK	Out of state	500,000.00	OK	0.00%	-	2021
1660000	System Growth	DIMMIT DAIRY FARM WORK	376.0	211130	LUBBOCK AREA - RURAL	Non-jurisdictional	32,357.14	TX	100.00%	32,357.14	2021
1660001	System Growth	COMPLETE FISCHBACHER BID	376.0	211130	AMARILLO	Jurisdictional	1,750.00	TX	100.00%	1,750.00	2021
1660002	System Growth	NEW ADDITION VAN HORN	376.0	211130	AMARILLO	Jurisdictional	13,140.00	TX	100.00%	13,140.00	2021
1660012	System Growth	PO 25605 BURGER KING	376.0	211231	SAN ANTONIO AREA - RURAL	Jurisdictional	18,117.78	TX	100.00%	18,117.78	2021
1660014	System Growth	PO 26668 OSLO PROJECT	376.0	211231	STRATFORD & ENVIRONS	Non-jurisdictional	18,857.21	TX	100.00%	18,857.21	2021
1660015	System Growth	PO 26772 WILLARD	376.0	211231	STRATFORD & ENVIRONS	Jurisdictional	2,200.00	TX	100.00%	2,200.00	2021
1660016	System Growth	PO 26872 STRATFORD	376.0	211231	STRATFORD & ENVIRONS	Jurisdictional	50,486.35	TX	100.00%	50,486.35	2021
1660017	System Growth	PO 26992 GATEWAY	376.0	211231	DALHART AREA - RURAL	Non-jurisdictional	28,167.48	TX	100.00%	28,167.48	2021
1660018	System Growth	PO 27348 CACTUS	376.0	211231	CACTUS & ENVIRONS	Jurisdictional	8,396.19	TX	100.00%	8,396.19	2021
1660020	System Integrity	PO 27383 TBS UPGRADE	376.0	211231	KERMIT & ENVIRIONS	Jurisdictional	24,558.73	TX	100.00%	24,558.73	2021
1660024	System Growth	PO 27647 REED TO ALLEN	376.0	211231	CANADIAN AREA TX - RURAL	Jurisdictional	92,688.99	TX	100.00%	92,688.99	2021
1660025	System Growth	PO 27677 EXUM GAS SUPPLY	376.0	211231	DALHART AREA - RURAL	Non-jurisdictional	933,684.51	TX	100.00%	933,684.51	2021

1660026	System Growth	PO 27679 FARIA UPGRADE	376.0	211231	DALHART AREA - RURAL	Non-jurisdictional	2,130.00	TX	100.00%	2,130.00	2021
1660027	System Growth	PO 27685 KOEHN SYSTEM	376.0	211231	TEXHOMA TX & ENVIRONS	Non-jurisdictional	15,920.82	TX	100.00%	15,920.82	2021
1660028	System Growth	PO 27725 EQUITY EXCHANGE	376.0	211231	CANADIAN AREA TX - RURAL	Non-jurisdictional	9,243.20	TX	100.00%	9,243.20	2021
1660030	System Growth	PO 27827 WADDELL PROJECT	376.0	211231	CLAUDE & ENVIRONS	Jurisdictional	5,025.99	TX	100.00%	5,025.99	2021
1660031	System Growth	PO 27832 HENRY REID UNIT	376.0	211231	DALHART AREA - RURAL	Jurisdictional	5,187.75	TX	100.00%	5,187.75	2021
1660033	System Growth	PO 27855 AMAZON FACILITY	376.0	211231	SOMERSET & ENVIRONS	Jurisdictional	32,700.85	TX	100.00%	32,700.85	2021
1660034	System Growth	PO 27882 ETC GENE BORN	376.0	211231	FOLLETT & ENVIRONS	Jurisdictional	7,460.00	TX	100.00%	7,460.00	2021
1660035	System Growth	PO 27948 FARIA DAIRY &	376.0	211231	DALHART AREA - RURAL	Non-jurisdictional	24,817.71	TX	100.00%	24,817.71	2021
1660036	System Integrity	PO 27971 REROUTE P/L IN	376.0	211231	TRANS PECOS AREA - RURAL	Jurisdictional	110,626.96	TX	100.00%	110,626.96	2021
1660039	System Growth	PO 28049 THOMAS REDIMIX	376.0	211231	AMARILLO AREA - RURAL	Jurisdictional	9,980.63	TX	100.00%	9,980.63	2021
1660040	System Growth	PO 28118 HOG PEN ADDITION	376.0	211231	AMARILLO AREA - RURAL	Jurisdictional	6,125.57	TX	100.00%	6,125.57	2021
1660042	DIMP	PO 90230 2021 DIMP KERMIT	376.0	211231	KERMIT & ENVIRONS	Jurisdictional	855,575.78	TX	100.00%	855,575.78	2021
1660043	DIMP	PO 90231 2021 DIMP	376.0	211231	IMPERIAL ENVIRONS	Jurisdictional	1,958.63	TX	100.00%	1,958.63	2021
1660044	DIMP	PO 90232 2021 DIMP	376.0	211231	BALMORHEA & ENVIRONS	Jurisdictional	71,565.53	TX	100.00%	71,565.53	2021
1660045	DIMP	PO 90233 2021 DIMP TP	376.0	211231	TRANS PECOS AREA - RURAL	Jurisdictional	20,383.00	TX	100.00%	20,383.00	2021
1660046	DIMP	PO 90236 2021 DIMP	376.0	211231	JUNCTION & ENVIRONS	Jurisdictional	293,204.49	TX	100.00%	293,204.49	2021
1660047	DIMP	PO 90237 2021 DIMP MENARD	376.0	211231	MENARD & ENVIRONS	Jurisdictional	29,155.18	TX	100.00%	29,155.18	2021
1660048	DIMP	PO 90238 2021 DIMP SONORA	376.0	211231	SONORA & ENVIRONS	Jurisdictional	72,453.81	TX	100.00%	72,453.81	2021
1660049	DIMP	PO 90239 2021 DIMP EDEN	376.0	211231	EDEN & ENVIRONS	Jurisdictional	512,408.65	TX	100.00%	512,408.65	2021
1660050	DIMP	PO 90243 2021 DIMP	376.0	211231	CANADIAN & ENVIRONS	Jurisdictional	967,706.11	TX	100.00%	967,706.11	2021
1660051	DIMP	PO 90244 2021 DIMP	376.0	211231	WHEELER TX & ENVIRONS	Jurisdictional	256,610.02	TX	100.00%	256,610.02	2021
1660052	DIMP	PO 90245 2021 DIMP	376.0	211231	SHAMROCK & ENVIRONS	Jurisdictional	337,659.24	TX	100.00%	337,659.24	2021
1660053	DIMP	PO 90247 2021 DIMP	376.0	211231	DARROUZETT & ENVIRONS	Jurisdictional	987.87	TX	100.00%	987.87	2021
1660054	DIMP	PO 90248 2021 DIMP	376.0	211231	FOLLETT & ENVIRONS	Jurisdictional	256,951.35	TX	100.00%	256,951.35	2021
1660055	DIMP	PO 90249 2021 DIMP MIAMI	376.0	211231	MIAMI & ENVIRONS	Jurisdictional	300,688.32	TX	100.00%	300,688.32	2021
1660056	DIMP	PO 90250 2021 DIMP	376.0	211231	MOBEETIE & ENVIRONS	Jurisdictional	13,022.31	TX	100.00%	13,022.31	2021
1660057	DIMP	PO 90251 2021 DIMP	376.0	211231	CANADIAN AREA TX - RURAL	Jurisdictional	4,436.74	TX	100.00%	4,436.74	2021
1660058	DIMP	PO 90252 2021 DIMP GROOM	376.0	211231	GROOM & ENVIRONS	Jurisdictional	6,239.16	TX	100.00%	6,239.16	2021
1660059	DIMP	PO 90253 2021 DIMP	376.0	211231	FARWELL & ENVIRONS	Jurisdictional	994,279.98	TX	100.00%	994,279.98	2021
1660060	DIMP	PO 90254 2021 DIMP CLAUDE	376.0	211231	CLAUDE & ENVIRONS	Jurisdictional	1,076.12	TX	100.00%	1,076.12	2021
1660061	DIMP	PO 90255 2021 DIMP WHITE	376.0	211231	WHITE DEER & ENVIRONS	Jurisdictional	329,586.24	TX	100.00%	329,586.24	2021
1660062	DIMP	PO 90262 2021 DIMP	376.0	211231	STRATFORD & ENVIRONS	Jurisdictional	351,215.12	TX	100.00%	351,215.12	2021
1660063	DIMP	PO 90264 2021 DIMP	376.0	211231	TEXHOMA OK	Out of state	128,910.29	OK	0.00%	-	2021
1660066	DIMP	PO 90269 2021 DIMP DEVINE	376.0	211231	DEVINE & ENVIRONS	Jurisdictional	26,116.49	TX	100.00%	26,116.49	2021
1660067	DIMP	PO 90271 2021 DIMP	376.0	211231	NATALIA & ENVIRONS	Jurisdictional	643,066.29	TX	100.00%	643,066.29	2021
1660068	DIMP	PO 90272 2021 DIMP SAN	376.0	211231	SAN ANTONIO AREA - RURAL	Jurisdictional	3,192.24	TX	100.00%	3,192.24	2021
1660069	DIMP	PO 90273 2021 DIMP VAN	376.0	211231	VAN HORN & ENVIRONS	Jurisdictional	56,938.11	TX	100.00%	56,938.11	2021
160013	System Integrity	PO 26024 RATTRAY UPGRADE	376.0	211231	BOISE CITY OK	Out of state	35,682.85	OK	0.00%	-	2021
160019	System Growth	PO 26701 FELT NTH 2020	376.0	211231	TEXHOMA OK	Out of state	23,982.06	OK	0.00%	-	2021
160022	System Growth	PO 27495 USA FEEDERS	376.0	211231	BEAVER OK	Out of state	1,725.00	OK	0.00%	-	2021
160029	System Growth	PO 27806 HAAR PROJECT	376.0	211231	TEXHOMA OK	Out of state	13,889.35	OK	0.00%	-	2021
160037	System Integrity	PO 27981 DRY TRAILS 4"	376.0	211231	TEXHOMA OK	Out of state	28,353.92	OK	0.00%	-	2021
160041	System Integrity	PO 28130 TURPIN N PROJECT	376.0	211231	BEAVER OK	Out of state	27,362.00	OK	0.00%	-	2021
1660064	DIMP	PO 90266 2021 DIMP BOISE	376.0	211231	BOISE CITY OK	Out of state	901,972.25	OK	0.00%	-	2021
1660065	DIMP	PO 90267 2021 DIMP BEAVER	376.0	211231	BEAVER OK	Out of state	731,686.92	OK	0.00%	-	2021
1769932	Measurement	ROOTS METER 5M175 CD 3"	378.0	210131	SAN ANTONIO AREA - RURAL	Jurisdictional	2,669.40	TX	100.00%	2,669.40	2021
1769933	Measurement	FS500 SICK ULTRASONIC	378.0	210131	DALHART AREA - RURAL	Jurisdictional	6,295.71	TX	100.00%	6,295.71	2021
1769935	Measurement	FLOW COMPUTER XFC6414	378.0	210228	LUBBOCK	Jurisdictional	3,405.76	TX	100.00%	3,405.76	2021
1769939	Measurement	ROOTS METER 3M175	378.0	210331	TRANS PECOS AREA - RURAL	Jurisdictional	3,167.69	TX	100.00%	3,167.69	2021
1769940	Measurement	EC350 VOLUME CORRECTOR	378.0	210331	DALHART AREA - RURAL	Jurisdictional	3,580.54	TX	100.00%	3,580.54	2021
1769972	Measurement	3M175 LMMA DRESSER ROTARY	378.0	210531	DALHART AREA - RURAL	Jurisdictional	3,361.16	TX	100.00%	3,361.16	2021
1759977	Measurement	ELECTRONIC VOLUME	378.0	210731	DALHART AREA - RURAL	Jurisdictional	5,535.43	TX	100.00%	5,535.43	2021
1759978	Measurement	ROOTS METER 3M175	378.0	210731	KERMIT & ENVIRIONS	Jurisdictional	4,410.55	TX	100.00%	4,410.55	2021
1759987	Measurement	MOONEY FLOWGRID 2", FS500	378.0	210930	DALHART AREA - RURAL	Jurisdictional	17,120.96	TX	100.00%	17,120.96	2021
259988	Measurement	REGULATOR 1" NPT	378.0	210930	TEXHOMA OK	Out of state	2,122.38	OK	0.00%	-	2021
1759994	Measurement	ROOTS METER 3M175 CD	378.0	211031	LUBBOCK AREA - RURAL	Jurisdictional	2,423.53	TX	100.00%	2,423.53	2021
1759995	Measurement	METER REBUILDS 5M175	378.0	211031	DALHART AREA - RURAL	Jurisdictional	6,329.38	TX	100.00%	6,329.38	2021
1760007	Measurement	REGULATOR 2" ANSI 150	378.0	211231	SOMERSET & ENVIRONS	Jurisdictional	3,517.23	TX	100.00%	3,517.23	2021
1760008	Measurement	FS500 SICK ULTRASONIC	378.0	211231	CANADIAN AREA TX - RURAL	Jurisdictional	11,247.91	TX	100.00%	11,247.91	2021
1760021	Measurement	PO 27395 SOMERSET METER	378.0	211231	SOMERSET & ENVIRONS	Jurisdictional	34,531.26	TX	100.00%	34,531.26	2021
1760032	Measurement	PO 27839 HWY 90 CHECK	378.0	211231	SOMERSET & ENVIRONS	Jurisdictional	15,585.54	TX	100.00%	15,585.54	2021
2169936	Field Equipment	ELECTOFUSION PROCESSOR	387.0	210228	CANADIAN & ENVIRONS	Jurisdictional	906.21	TX	100.00%	906.21	2021
2160003	Field Equipment	SENSIT GOLD G2 TC EX/TC/	387.0	211130	WHEELER TX & ENVIRONS	Jurisdictional	2,858.30	TX	100.00%	2,858.30	2021
5769934	Office Equipment	2 1/2 TON HVAC SYSTEM	391.0	210131	SHAMROCK & ENVIRONS	Both	6,964.38	TX	100.00%	6,964.38	2021
5769945	Office Equipment	11 IPAD PRO 128GB SGRAY	391.0	210331	KERMIT & ENVIRIONS	Both	883.99	TX	100.00%	883.99	2021
5769946	Office Equipment	KYOCERA ECOSYS M3655IDN	391.0	210331	VAN HORN & ENVIRONS	Both	6,765.63	TX	100.00%	6,765.63	2021
5769969	Office Equipment	KYOCERA ECOSYS M3655IDN	391.0	210531	SHAMROCK & ENVIRONS	Both	6,765.63	TX	100.00%	6,765.63	2021
5169937	Equipment	UNIT 11090 2021 SILVERADO	392.0	210228	SAN ANTONIO AREA - RURAL	Both	33,484.00	TX	100.00%	33,484.00	2021
5169938	Equipment	UNIT 11091 2021 SILVERADO	392.0	210228	CANADIAN & ENVIRONS	Both	33,484.00	TX	100.00%	33,484.00	2021
5169941	Equipment	UNIT 11104 2021 SILVERADO	392.0	210331	JUNCTION & ENVIRONS	Both	33,272.00	TX	100.00%	33,272.00	2021
5169942	Equipment	UNIT 11105 2021 SILVERADO	392.0	210331	TRANS PECOS AREA - RURAL	Both	37,190.00	TX	100.00%	37,190.00	2021
5169943	Equipment	UNIT 11089 2021 SILVERADO	392.0	210331	DALHART AREA - RURAL	Both	37,987.96	TX	100.00%	37,987.96	2021
5169968	Equipment	UNIT 11115 2021 SILVERADO	392.0	210531	LUBBOCK AREA - RURAL	Both	37,190.00	TX	100.00%	37,190.00	2021
5169974	Equipment	UNIT 11127 2021 SILVERADO	392.0	210630	GROOM & ENVIRONS	Both	37,863.00	TX	100.00%	37,863.00	2021
6269975	Equipment	UNIT 11122 2021 SILVERADO	392.0	210630	TEXHOMA OK	Out of state	34,652.36	OK	0.00%	-	2021
5159979	Equipment	UNIT 11128 2021 SILVERADO	392.0	210731	AMARILLO	Both	33,484.00	TX	100.00%	33,484.00	2021
5159980	Equipment	UNIT 11129 2021 SIERRA	392.0	210731	SAN ANTONIO AREA - RURAL	Both	37,864.00	TX	100.00%	37,864.00	2021
5159981	Equipment	UNIT 11131 2021 SILVERADO	392.0	210731	AMARILLO	Both	33,272.00	TX	100.00%	33,272.00	2021
5469944	Field Equipment	2015 CAT 303E COMPACT	394.0	210331	TRANS PECOS AREA - RURAL	Both	29,227.50	TX	100.00%	29,227.50	2021
5469947	Field Equipment	2016 CAT 303E COMPACT	394.0	210331	LUBBOCK	Both	29,227.50	TX	100.00%	29,227.50	2021

5969949	Field Equipment	SENSIT GOLD G2 TC EX/TC/	394.0	210430	TRANS PECOS AREA - RURAL	Both	2,844.62	TX	100.00%	2,844.62	2021
5969950	Field Equipment	LOCATOR 8879V4	394.0	210430	TRANS PECOS AREA - RURAL	Both	4,020.76	TX	100.00%	4,020.76	2021
5969970	Field Equipment	SENSIT GOLD G2 TC EX/TC/	394.0	210531	DALHART AREA - RURAL	Both	2,629.89	TX	100.00%	2,629.89	2021
6569976	Field Equipment	22' PJ TANDEM AXLE FLAT	394.0	210630	TEXHOMA OK	Out of state	4,000.00	OK	0.00%	-	2021
5959985	Field Equipment	INTERNATIONAL AIR TOOL	394.0	210831	JUNCTION & ENVIRONS	Both	1,241.56	TX	100.00%	1,241.56	2021
5959986	Field Equipment	INTERNATIONAL AIR TOOL	394.0	210831	CANADIAN & ENVIRONS	Both	1,241.56	TX	100.00%	1,241.56	2021
5959991	Field Equipment	SQUEEZE TOOL 1-4 C156	394.0	210930	LUBBOCK AREA - RURAL	Both	1,345.55	TX	100.00%	1,345.55	2021
5959992	Field Equipment	THICKNESS GAUGE TI-45NA	394.0	210930	TRANS PECOS AREA - RURAL	Both	1,637.83	TX	100.00%	1,637.83	2021
5959993	Field Equipment	RMLD-CS, COMPLETE	394.0	210930	TRANS PECOS AREA - RURAL	Both	16,680.19	TX	100.00%	16,680.19	2021
5959996	Field Equipment	SENSIT GOLD CO O2	394.0	211031	TRANS PECOS AREA - RURAL	Both	3,282.07	TX	100.00%	3,282.07	2021
5960010	Field Equipment	SQUEEZE TOOL 1-4 C156	394.0	211231	SOMERSET & ENVIRONS	Both	1,432.74	TX	100.00%	1,432.74	2021
5960011	Field Equipment	PROCESSOR EF MTD BATTERY	394.0	211231	TRANS PECOS AREA - RURAL	Both	5,349.88	TX	100.00%	5,349.88	2021
5660023	Communication Equipmer	PO 27545 MAXWELL INTERNET	397.0	211231	SOMERSET & ENVIRONS	Both	4,097.94	TX	100.00%	4,097.94	2021
6059983	Equipment	2021 BUCK 450	398.0	210831	CANADIAN AREA TX - RURAL	Both	11,368.43	TX	100.00%	11,368.43	2021
6060004	Equipment	40' HIGH CUBE CONTAINER	398.0	211130	GUYMON AREA TX - RURAL	Both	7,750.00	TX	100.00%	7,750.00	2021
5159989	Equipment	UNIT 11134 2021 DODGE	392.0	210930	HOME OFFICE G&A	Both	56,349.55	CORP	94.25%	53,109.45	2021
5159990	Equipment	UNIT 11135 2021 GMC	392.0	210930	HOME OFFICE G&A	Both	36,144.47	CORP	94.25%	34,066.16	2021
5159999	Equipment	UNIT 40001 2022 GMC	392.0	211130	HOME OFFICE G&A	Both	54,026.48	CORP	94.25%	50,919.96	2021
5160005	Equipment	UNIT 40002 2022 SILVERADO	392.0	211130	HOME OFFICE G&A	Both	40,329.00	CORP	94.25%	38,010.08	2021
5160006	Equipment	UNIT 40003 2022 SILVERADO	392.0	211130	HOME OFFICE G&A	Both	40,329.00	CORP	94.25%	38,010.08	2021
5160009	Equipment	UNIT 40004 2022 SILVERADO	392.0	211231	HOME OFFICE G&A	Both	40,329.00	CORP	94.25%	38,010.08	2021
5959997	Field Equipment	9000W GENERATOR - CABELAS	394.0	211031	HOME OFFICE G&A	Both	800.00	CORP	94.25%	754.00	2021
6059998	Equipment	8' X 20' X 8.5' ONE-TRIP	398.0	211031	HOME OFFICE G&A	Both	5,871.25	CORP	94.25%	5,533.65	2021
3569833	System Growth	WHISTLER PIPELINE INTER	367.0	200731	SAN ANTONIO AREA - RURAL	Jurisdictional	683,000.00	TX	100.00%	683,000.00	2020
3569838	System Growth	PO 24154 BLACK MOUNTAIN	367.0	200731	SAN ANTONIO AREA - RURAL	Jurisdictional	1,513,968.27	TX	100.00%	1,513,968.27	2020
3569840	System Integrity	PO 25638 EL INDIO LOOP	367.0	200731	SAN ANTONIO AREA - RURAL	Jurisdictional	30,217.50	TX	100.00%	30,217.50	2020
3569843	System Growth	PO 26010 TGU REEF	367.0	200731	SAN ANTONIO AREA - RURAL	Jurisdictional	324,320.78	TX	100.00%	324,320.78	2020
1669846	System Growth	PO 26509 FRIO 6" STEEL	367.0	200731	SAN ANTONIO AREA - RURAL	Jurisdictional	3,830,384.57	TX	100.00%	3,830,384.57	2020
3669930	Measurement	PO 27536 MEEK REGULATION	369.0	201231	CANADIAN AREA TX - RURAL	Jurisdictional	11,105.91	TX	100.00%	11,105.91	2020
7769805	System Growth	SERVICE TO COMET CLEANERS	376.0	200430	LUBBOCK	Jurisdictional	1,190.00	TX	100.00%	1,190.00	2020
7769806	System Growth	NEW SERVICE	376.0	200430	LUBBOCK	Jurisdictional	2,190.00	TX	100.00%	2,190.00	2020
7769807	System Growth	NEW SERVICE TO AG	376.0	200430	STRATFORD & ENVIRONS	Non-jurisdictional	2,350.00	TX	100.00%	2,350.00	2020
1669828	System Growth	DRY TRAILS GAS LINE	376.0	200731	GUYMON AREA TX - RURAL	Jurisdictional	15,865.00	TX	100.00%	15,865.00	2020
1669829	System Growth	LAY NEW 2' PIPE AND SET	376.0	200731	LUBBOCK	Jurisdictional	2,968.00	TX	100.00%	2,968.00	2020
1669830	System Growth	NEW SERVICE ALAN CLEMANS	376.0	200731	TEXHOMA OK	Out of state	2,972.00	OK	0.00%	-	2020
1669837	System Growth	PO 23616 COTULLA EL INDIO	376.0	200731	SAN ANTONIO AREA - RURAL	Jurisdictional	2,322.67	TX	100.00%	2,322.67	2020
1669839	System Growth	PO 24322 MAAS ENERGY	376.0	200731	DALHART AREA - RURAL	Non-jurisdictional	72,461.31	TX	100.00%	72,461.31	2020
1669842	System Growth	PO 25791 SAVANNAH GATES	376.0	200731	LUBBOCK AREA - RURAL	Jurisdictional	56,985.16	TX	100.00%	56,985.16	2020
1669844	System Growth	PO 26150 LONGVIEW HOG	376.0	200731	DALHART AREA - RURAL	Non-jurisdictional	144,272.97	TX	100.00%	144,272.97	2020
1669847	System Growth	PO 26731 GOLDEN SPREAD	376.0	200731	AMARILLO AREA - RURAL	Jurisdictional	34,247.37	TX	100.00%	34,247.37	2020
1669848	System Growth	PO 26774 HEISKELL LATERAL	376.0	200731	DALHART AREA - RURAL	Jurisdictional	23,308.00	TX	100.00%	23,308.00	2020
1669849	System Growth	PO 26865 BRINKMAN TIE IN	376.0	200731	DALHART AREA - RURAL	Jurisdictional	4,887.19	TX	100.00%	4,887.19	2020
1669850	System Growth	PO 26866 HAAR IRRIGATION	376.0	200731	GUYMON AREA TX - RURAL	Non-jurisdictional	14,556.75	TX	100.00%	14,556.75	2020
1669851	System Growth	PO 26936 LUNSFORD PROJECT	376.0	200731	DALHART AREA - RURAL	Non-jurisdictional	136,596.84	TX	100.00%	136,596.84	2020
1669852	System Growth	PO 26996 RAFTER 3 FEEDLOT	376.0	200731	AMARILLO AREA - RURAL	Non-jurisdictional	65,081.75	TX	100.00%	65,081.75	2020
1669853	System Growth	PO 27049 HIGHLAND SPRINGS	376.0	200731	GROOM & ENVIRONS	Jurisdictional	154,173.77	TX	100.00%	154,173.77	2020
1669856	System Growth	PO 27138 KANSAS 4"	376.0	200731	GUYMON AREA TX - RURAL	Non-jurisdictional	203,280.38	TX	100.00%	203,280.38	2020
1669857	System Growth	PO 27214 NEW SERVICE	376.0	200731	AMARILLO	Jurisdictional	3,500.00	TX	100.00%	3,500.00	2020
1669858	System Growth	PO 27218 FM 2219 LINE	376.0	200731	AMARILLO	Jurisdictional	3,139.77	TX	100.00%	3,139.77	2020
1669859	System Growth	PO 27289 REED BARNHILL	376.0	200731	DALHART AREA - RURAL	Jurisdictional	8,115.90	TX	100.00%	8,115.90	2020
1669862	System Growth	SERVICE TO MESA VIEW	376.0	200831	CANADIAN & ENVIRONS	Jurisdictional	5,780.00	TX	100.00%	5,780.00	2020
1669880	System Growth	HALE 133 IRRIGATION TAP	376.0	201130	STRATFORD & ENVIRONS	Non-jurisdictional	5,000.00	TX	100.00%	5,000.00	2020
1669883	System Integrity	MILLERSVIEW RECTIFIER	376.0	201231	JUNCTION & ENVIRONS	Jurisdictional	11,520.00	TX	100.00%	11,520.00	2020
1669888	System Integrity	PO 25805 PIPELINE FILTER	376.0	201231	DALHART AREA - RURAL	Jurisdictional	52,448.55	TX	100.00%	52,448.55	2020
1669889	System Growth	PO 26002 PILOT TRUCK STOP	376.0	201231	TRANS PECOS AREA - RURAL	Jurisdictional	21,001.61	TX	100.00%	21,001.61	2020
1669890	System Growth	PO 26120 COBBLESTONE	376.0	201231	KERMIT & ENVIRIONS	Jurisdictional	1,822.50	TX	100.00%	1,822.50	2020
1669891	System Growth	PO 27058 LOVE'S PROJECT	376.0	201231	KERMIT & ENVIRIONS	Jurisdictional	24,303.60	TX	100.00%	24,303.60	2020
1669892	System Growth	PO 27143 FOLLETT EXTENION	376.0	201231	CANADIAN & ENVIRONS	Jurisdictional	1,342,874.19	TX	100.00%	1,342,874.19	2020
1669893	System Growth	PO 27156 MULTI-CHEM	376.0	201231	SONORA & ENVIRONS	Jurisdictional	536,432.26	TX	100.00%	536,432.26	2020
1669894	System Growth	PO 27405 TEJAS FEEDERS	376.0	201231	CANADIAN & ENVIRONS	Non-jurisdictional	63,949.40	TX	100.00%	63,949.40	2020
1669895	System Growth	PO 27432 WHITE HOUSE SAND	376.0	201231	AMARILLO AREA - RURAL	Jurisdictional	2,500.00	TX	100.00%	2,500.00	2020
1669896	System Growth	PO 27438 T-3 FARM TAP	376.0	201231	CANADIAN & ENVIRONS	Jurisdictional	38,724.63	TX	100.00%	38,724.63	2020
1669897	System Integrity	PO 27566 REPLACE LATERAL	376.0	201231	SAN ANTONIO AREA - RURAL	Jurisdictional	12,996.28	TX	100.00%	12,996.28	2020
1669898	DIMP	PO 90187 KERMIT DIMP 2020	376.0	201231	KERMIT & ENVIRIONS	Jurisdictional	886,640.00	TX	100.00%	886,640.00	2020
1669899	DIMP	PO 90189 BALMORHEA DIMP	376.0	201231	BALMORHEA & ENVIRONS	Jurisdictional	69,584.52	TX	100.00%	69,584.52	2020
1669900	DIMP	PO 90190 TP RURAL DIMP	376.0	201231	TRANS PECOS AREA - RURAL	Jurisdictional	402,482.83	TX	100.00%	402,482.83	2020
1669901	DIMP	PO 90193 JUNCTION DIMP	376.0	201231	JUNCTION & ENVIRONS	Jurisdictional	598,228.43	TX	100.00%	598,228.43	2020
1669902	DIMP	PO 90194 MENARD DIMP 2020	376.0	201231	MENARD & ENVIRONS	Jurisdictional	91,352.20	TX	100.00%	91,352.20	2020
1669903	DIMP	PO 90195 SONORA DIMP 2020	376.0	201231	SONORA & ENVIRONS	Jurisdictional	592,109.14	TX	100.00%	592,109.14	2020
1669904	DIMP	PO 90196 EDEN DIMP 2020	376.0	201231	EDEN & ENVIRONS	Jurisdictional	69,991.73	TX	100.00%	69,991.73	2020
1669905	DIMP	PO 90200 CANADIAN DIMP	376.0	201231	CANADIAN & ENVIRONS	Jurisdictional	44,289.26	TX	100.00%	44,289.26	2020
1669906	DIMP	PO 90201 WHEELER TX DIMP	376.0	201231	WHEELER TX & ENVIRONS	Jurisdictional	218,841.18	TX	100.00%	218,841.18	2020
1669907	DIMP	PO 90202 SHAMROCK DIMP	376.0	201231	SHAMROCK & ENVIRONS	Jurisdictional	108,926.54	TX	100.00%	108,926.54	2020
1669908	DIMP	PO 90203 HIGGINS DIMP	376.0	201231	HIGGINS & ENVIRONS	Jurisdictional	11,558.68	TX	100.00%	11,558.68	2020
1669909	DIMP	PO 90204 DARROUZETT DIMP	376.0	201231	DARROUZETT & ENVIRONS	Jurisdictional	1,185.51	TX	100.00%	1,185.51	2020
1669910	DIMP	PO 90205 FOLLETT DIMP	376.0	201231	FOLLETT & ENVIRONS	Jurisdictional	231,338.32	TX	100.00%	231,338.32	2020
1669911	DIMP	PO 90206 MIAMI DIMP 2020	376.0	201231	MIAMI & ENVIRONS	Jurisdictional	10,396.10	TX	100.00%	10,396.10	2020
1669912	DIMP	PO 90207 MOBEETIE DIMP	376.0	201231	MOBEETIE & ENVIRONS	Jurisdictional	714,541.79	TX	100.00%	714,541.79	2020
1669913	DIMP	PO 90208 CANADIAN RURAL	376.0	201231	CANADIAN AREA TX - RURAL	Jurisdictional	24,695.31	TX	100.00%	24,695.31	2020
1669914	DIMP	PO 90209 GROOM DIMP 2020	376.0	201231	GROOM & ENVIRONS	Jurisdictional	492,337.76	TX	100.00%	492,337.76	2020

1669915	DIMP	PO 90210 FARWELL DIMP	376.0	201231	FARWELL & ENVIRONS	Jurisdictional	449,052.06	TX	100.00%	449,052.06	2020
1669916	DIMP	PO 90211 CALUDE DIMP 2020	376.0	201231	CLAUDE & ENVIRONS	Jurisdictional	10,381.57	TX	100.00%	10,381.57	2020
1669917	DIMP	PO 90212 WHITE DEER DIMP	376.0	201231	WHITE DEER & ENVIRONS	Jurisdictional	414,600.75	TX	100.00%	414,600.75	2020
1669918	DIMP	PO 90217 TEXLINE DIMP	376.0	201231	TEXLINE & ENVIRONS	Jurisdictional	419,153.44	TX	100.00%	419,153.44	2020
1669919	DIMP	PO 90219 STRATFORD DIMP	376.0	201231	STRATFORD & ENVIRONS	Jurisdictional	234,548.59	TX	100.00%	234,548.59	2020
1669920	DIMP	PO 90220 CACTUS DIMP 2020	376.0	201231	CACTUS & ENVIRONS	Jurisdictional	363,386.19	TX	100.00%	363,386.19	2020
1669921	DIMP	PO 90225 SOMERSET DIMP	376.0	201231	SOMERSET & ENVIRONS	Jurisdictional	712,995.38	TX	100.00%	712,995.38	2020
1669922	DIMP	PO 90228 NATALIA DIMP	376.0	201231	NATALIA & ENVIRONS	Jurisdictional	939,810.84	TX	100.00%	939,810.84	2020
1669923	DIMP	PO 90229 SA RURAL DIMP	376.0	201231	SAN ANTONIO AREA - RURAL	Jurisdictional	15,173.74	TX	100.00%	15,173.74	2020
1769877	Measurement	ROOTS METER 75175 CD 3"	376.0	201031	STRATFORD & ENVIRONS	Jurisdictional	3,362.19	TX	100.00%	3,362.19	2020
169854	System Growth	PO 27137 HAAR 6'	376.0	200731	TEXHOMA OK	Out of state	228,600.20	OK	0.00%	-	2020
169854	System Growth	PO 27137 HAAR 6'	376.0	200731	TEXHOMA OK	Out of state	7,724.49	OK	0.00%	-	2020
169924	System Growth	PO 26625 HITCH FEEDERS	376.0	201231	BEAVER OK	Out of state	61,019.74	OK	0.00%	-	2020
169925	DIMP	PO 90223 BOISE CITY DIMP	376.0	201231	BOISE CITY OK	Out of state	57,449.79	OK	0.00%	-	2020
169926	DIMP	PO 90224 BEAVER DIMP 2020	376.0	201231	BEAVER OK	Out of state	106,011.42	OK	0.00%	-	2020
1769788	Measurement	MODEL EFLO6213 FLOW	378.0	200229	SHAMROCK & ENVIRONS	Jurisdictional	2,670.83	TX	100.00%	2,670.83	2020
1769793	Measurement	SICK FS500 LCD DISPLAY	378.0	200331	KERMIT & ENVIRONS	Jurisdictional	3,297.40	TX	100.00%	3,297.40	2020
1769794	Measurement	MPPLUS VOLUME CORRECTOR	378.0	200331	WHEELER TX & ENVIRONS	Jurisdictional	2,301.69	TX	100.00%	2,301.69	2020
1769795	Measurement	ROOTS METER 056318-020	378.0	200331	DALHART AREA - RURAL	Jurisdictional	11,378.17	TX	100.00%	11,378.17	2020
1769813	Measurement	ROOTS METER 3M175	378.0	200531	DALHART AREA - RURAL	Jurisdictional	2,911.34	TX	100.00%	2,911.34	2020
1769814	Measurement	ROOTS METER 3M175	378.0	200531	DALHART AREA - RURAL	Jurisdictional	3,592.19	TX	100.00%	3,592.19	2020
1769816	Measurement	REGULATOR B42R 1" NPT	378.0	200531	TEXHOMA OK	Out of state	957.00	OK	0.00%	-	2020
1769821	Measurement	REGULATORA 2" ANSI 300	378.0	200630	LUBBOCK	Jurisdictional	11,056.54	TX	100.00%	11,056.54	2020
1769822	Measurement	ROOTS METER 11M175 CD	378.0	200630	CANADIAN & ENVIRONS	Jurisdictional	3,760.68	TX	100.00%	3,760.68	2020
1769831	Measurement	FS500 ULTRASONIC METER 3"	378.0	200731	LUBBOCK	Jurisdictional	6,279.27	TX	100.00%	6,279.27	2020
1769832	Measurement	FS500 SICK ULTRASONIC	378.0	200731	DALHART AREA - RURAL	Jurisdictional	7,922.15	TX	100.00%	7,922.15	2020
1769841	Measurement	PO 25692 SOLAR RECTIFIER	378.0	200731	TRANS PECOS AREA - RURAL	Jurisdictional	9,732.52	TX	100.00%	9,732.52	2020
1669845	Measurement	PO 26484 CHITTUM	378.0	200731	SAN ANTONIO AREA - RURAL	Jurisdictional	46,490.56	TX	100.00%	46,490.56	2020
1769866	Measurement	METER REBUILT ROTARY	378.0	200930	TEXHOMA OK	Out of state	6,568.47	OK	0.00%	-	2020
1769867	Measurement	FS500 SICK ULTRASONIC	378.0	200930	SOMERSET & ENVIRONS	Jurisdictional	14,967.32	TX	100.00%	14,967.32	2020
1769868	Measurement	ROOTS METER 5M1480	378.0	200930	TRANS PECOS AREA - RURAL	Jurisdictional	11,606.32	TX	100.00%	11,606.32	2020
1769874	Measurement	INSTALL NEW METER TO	378.0	201031	FARWELL & ENVIRONS	Jurisdictional	4,225.00	TX	100.00%	4,225.00	2020
1769875	Measurement	SICK FS600 DRU METER	378.0	201031	DALHART AREA - RURAL	Jurisdictional	20,437.05	TX	100.00%	20,437.05	2020
1769878	Measurement	4 ELECTRONIC VOLUME	378.0	201031	DALHART & ENVIRONS	Jurisdictional	7,989.68	TX	100.00%	7,989.68	2020
1769881	Measurement	ROOTS METER 5M175 CD 3"	378.0	201130	FARWELL & ENVIRONS	Jurisdictional	3,135.68	TX	100.00%	3,135.68	2020
1769884	Measurement	ROOTS METER 3M175 CTR 2"	378.0	201231	LUBBOCK	Jurisdictional	1,856.50	TX	100.00%	1,856.50	2020
1769927	Measurement	PO 27416 ROOTS METER FT	378.0	201231	TRANS PECOS AREA - RURAL	Jurisdictional	3,446.97	TX	100.00%	3,446.97	2020
1769928	Measurement	PO 27494 CANYON ISD METER	378.0	201231	CLAUDE & ENVIRONS	Jurisdictional	5,163.05	TX	100.00%	5,163.05	2020
269782	Measurement	MOONEY SERIES 20 PILOT,	378.0	200131	TEXHOMA OK	Out of state	879.62	OK	0.00%	-	2020
269783	Measurement	ROOTS METER, 5M175 CD 3"	378.0	200131	BOISE CITY OK	Out of state	5,597.01	OK	0.00%	-	2020
269792	Measurement	XRC PANEL, XRC G5 LARGE	378.0	200331	WHEELER OK	Out of state	3,202.97	OK	0.00%	-	2020
269808	Measurement	ELECTRONIC VOLUME	378.0	200430	TEXHOMA OK	Out of state	17,341.21	OK	0.00%	-	2020
269815	Measurement	266 HSH PRESSURE W/SURGE	378.0	200531	WHEELER OK	Out of state	2,132.58	OK	0.00%	-	2020
269863	Measurement	ROOTS METER 15C175 CD	378.0	200831	TEXHOMA OK	Out of state	1,577.69	OK	0.00%	-	2020
269876	Measurement	ROOTS METER 3M175 CD 2"	378.0	201031	BEAVER OK	Out of state	3,911.66	OK	0.00%	-	2020
7769804	Land	LAND PURCHASE - SPECIAL	389.1	200331	BEAVER OK	Out of state	12,000.00	OK	0.00%	-	2020
7069810	Equipment	CONTAINER INVENTORY	390.0	200430	KERMIT & ENVIRIONS	Jurisdictional	16,183.38	TX	100.00%	16,183.38	2020
7069811	Equipment	CONTAINER INVENTORY	390.0	200430	TRANS PECOS AREA - RURAL	Jurisdictional	16,183.38	TX	100.00%	16,183.38	2020
7069812	Equipment	LUBBOCK 40X40X16	390.0	200430	LUBBOCK	Jurisdictional	48,313.02	TX	100.00%	48,313.02	2020
7069819	Equipment	CONTIANER INVENTORY	390.0	200531	SOMERSET & ENVIRONS	Jurisdictional	16,183.38	TX	100.00%	16,183.38	2020
7069820	Equipment	CONTIANER INVENTORY	390.0	200531	JUNCTION & ENVIRONS	Jurisdictional	16,183.38	TX	100.00%	16,183.38	2020
5769827	Office Equipment	OPTIPLEX 7080 SFF XCTO	391.0	200630	AMARILLO	Both	1,610.89	TX	100.00%	1,610.89	2020
5769836	Office Equipment	DESK 36" X 72"	391.0	200731	SHAMROCK & ENVIRONS	Both	985.31	TX	100.00%	985.31	2020
5169789	Equipment	UNIT 11039 2020 SILVERADO	392.0	200229	LUBBOCK	Both	33,241.00	TX	100.00%	33,241.00	2020
5169790	Equipment	UNIT 11040 2019 SILVERADO	392.0	200229	DALHART AREA - RURAL	Both	35,261.00	TX	100.00%	35,261.00	2020
5169796	Equipment	UNIT 11043 SILVERADO REG	392.0	200331	SAN ANTONIO AREA - RURAL	Both	34,659.00	TX	100.00%	34,659.00	2020
5169797	Equipment	UNIT 11045 2020 SILVERADO	392.0	200331	EDEN & ENVIRONS	Both	36,610.00	TX	100.00%	36,610.00	2020
5169809	Equipment	UNIT 11046 2020 SILVERADO	392.0	200430	TRANS PECOS AREA - RURAL	Both	34,888.00	TX	100.00%	34,888.00	2020
5169810	Equipment	UNIT 11047 2020 SILVERADO	392.0	200430	DALHART & ENVIRONS	Both	36,869.13	TX	100.00%	36,869.13	2020
5169823	Equipment	UNIT 11050 2020 SILVERADO	392.0	200630	AMARILLO	Both	33,584.00	TX	100.00%	33,584.00	2020
5169824	Equipment	UNIT 11051 2020 SILVERADO	392.0	200630	AMARILLO	Both	33,773.00	TX	100.00%	33,773.00	2020
5169834	Equipment	UNIT 11057 2020 SILVERADO	392.0	200731	STRATFORD & ENVIRONS	Both	33,571.00	TX	100.00%	33,571.00	2020
5169835	Equipment	UNIT 11055 2020 SILVERADO	392.0	200731	GROOM & ENVIRONS	Both	48,823.70	TX	100.00%	48,823.70	2020
5169861	Equipment	UNIT 11061 2020 SILVERADO	392.0	200831	DALHART & ENVIRONS	Both	39,692.43	TX	100.00%	39,692.43	2020
5169864	Equipment	UNIT 11058 2020 GMC	392.0	200831	DALHART & ENVIRONS	Both	35,364.82	TX	100.00%	35,364.82	2020
5169869	Equipment	UNIT 11064 2020 SILVERADO	392.0	200930	SAN ANTONIO AREA - RURAL	Both	33,679.00	TX	100.00%	33,679.00	2020
5169870	Equipment	UNIT 11067 2020 SIERRA	392.0	200930	CANADIAN & ENVIRONS	Both	35,332.00	TX	100.00%	35,332.00	2020
5169871	Equipment	UNIT 11068 2020 SILVERADO	392.0	200930	STRATFORD & ENVIRONS	Both	36,716.00	TX	100.00%	36,716.00	2020
5169885	Equipment	UNIT 11081 2020 SIERRA	392.0	201231	LUBBOCK	Both	36,489.00	TX	100.00%	36,489.00	2020
5169886	Equipment	UNIT 11082 2020 SIERRA	392.0	201231	SAN ANTONIO AREA - RURAL	Both	34,979.00	TX	100.00%	34,979.00	2020
5169887	Equipment	UNIT 11083 2021 SILVERADO	392.0	201231	SAN ANTONIO AREA - RURAL	Both	33,697.00	TX	100.00%	33,697.00	2020
5269791	Equipment	MINI EXCAVATOR	392.0	200229	DALHART AREA - RURAL	Both	16,000.00	TX	100.00%	16,000.00	2020
6269803	Equipment	UNIT 11044 2020 SILVERADO	392.0	200331	BEAVER OK	Out of state	34,554.00	OK	0.00%	-	2020
5969784	Field Equipment	SENSIT GOLD G2 TC EX/TC/	394.0	200131	SHAMROCK & ENVIRONS	Both	2,105.35	TX	100.00%	2,105.35	2020
5869785	Field Equipment	SENSIT GOLD G2 TC EX/TC/	394.0	200229	STRATFORD & ENVIRONS	Both	4,751.62	TX	100.00%	4,751.62	2020
5969786	Field Equipment	SENSIT GOLD G2 TC EX/TC/	394.0	200229	GUYMON AREA TX - RURAL	Both	4,751.60	TX	100.00%	4,751.60	2020
5969799	Field Equipment	LOCATOR 8869V3 PLS 3 WATT	394.0	200331	SAN ANTONIO AREA - RURAL	Both	2,204.20	TX	100.00%	2,204.20	2020
5969800	Field Equipment	2 LINE LOCATORS	394.0	200331	DALHART AREA - RURAL	Both	4,660.16	TX	100.00%	4,660.16	2020
5969801	Field Equipment	LOCATOR 8869V3 PLS 3 WATT	394.0	200331	STRATFORD & ENVIRONS	Both	5,846.89	TX	100.00%	5,846.89	2020
5969802	Field Equipment	FOOT OPERATED HYDRAULIC	394.0	200331	SAN ANTONIO AREA - RURAL	Both	1,488.44	TX	100.00%	1,488.44	2020

5969826	Field Equipment	SOIL RESISTIVITY DIGITAL	394.0	200630	GROOM & ENVIRONS	Both	3,782.44	TX	100.00%	3,782.44	2020
5969860	Field Equipment	LOCATOR 8869V3 PLS 3 WATT	394.0	200731	SAN ANTONIO AREA - RURAL	Both	2,943.32	TX	100.00%	2,943.32	2020
5969865	Field Equipment	SENSIT GOLD CO2 MONITORS	394.0	200831	SOMERSET & ENVIRONS	Both	7,931.66	TX	100.00%	7,931.66	2020
5969872	Field Equipment	POLARIS RANGER 2017	394.0	200930	CANADIAN & ENVIRONS	Both	9,000.00	TX	100.00%	9,000.00	2020
5969873	Field Equipment	MODEL UFLO6213 FLOW	394.0	200930	TRANS PECOS AREA - RURAL	Both	3,065.09	TX	100.00%	3,065.09	2020
5969879	Field Equipment	SENSIT GOLD G2 EX/H2S	394.0	201031	GUYMON AREA TX - RURAL	Both	2,470.71	TX	100.00%	2,470.71	2020
5969882	Field Equipment	SENSIT GOLD G2 TC	394.0	201130	DALHART AREA - RURAL	Both	2,574.29	TX	100.00%	2,574.29	2020
6669787	Field Equipment	SENSIT GOLD G2 TC EX/TC	394.0	200229	BOISE CITY OK	Out of state	4,751.62	OK	0.00%	-	2020
6069817	Equipment	WELDING MACHINE AND	398.0	200531	SAN ANTONIO AREA - RURAL	Jurisdictional	2,500.00	TX	100.00%	2,500.00	2020
6069818	Equipment	REPLACED 3 TON AC SYSTEM	398.0	200531	AMARILLO	Both	5,000.00	TX	100.00%	5,000.00	2020
6069825	Equipment	GUYMON OFFICE SHOP HEATER	398.0	200630	GUYMON AREA TX - RURAL	Both	2,999.31	TX	100.00%	2,999.31	2020
5669881	Communication Equipmer	ITRON MOBILE RADIO	397.0	201130	HOME OFFICE G&A	Both	45,375.35	CORP	94.25%	42,766.27	2020

WORKPAPERS

TO

DIRECT TESTIMONY

OF

AMANDA EDGMON

Workpapers to the Direct Testimony of Amanda Edgmon are being provided in electronic format.

CASE NO. 00017816

STATEMENT OF INTENT OF WEST TEXAS GAS UTILITY, LLC TO INCREASE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF TEXAS	§ § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

MATTHEW S. SMITH, P.E.

ON BEHALF OF

WEST TEXAS GAS UTILITY, LLC

July 16, 2024

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LIST OF EXHIBITS

DIRECT TESTIMONY OF MATTHEW S. SMITH, P.E.

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew S. Smith. My business address is 303 Veterans Airpark Lane, Suite 5000, Midland, Texas 79705.

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

A. I am employed by West Texas Gas Utility, LLC ("WTGU" or the "Company") as the Vice President of Operations for its regulated pipeline systems.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF OPERATIONS FOR WTGU?

A. I am responsible for the execution of, and compliance with, WTGU's Operations and Maintenance Plan applicable to its distribution and transmission pipeline systems in Texas and Oklahoma. Additionally, I help to coordinate and oversee various levels of directors, managers, and supervisors. For instance, WTGU's Compliance director is directly responsible for the oversight and execution of Integrity Management, Distribution Integrity Management, Safety, Operations and Maintenance, Operator Qualification, and Public Awareness Plans. Operations directors and managers are responsible for operating the pipeline systems within certain assigned geographical areas. Field supervisors are responsible for the work performed by the service and maintenance staff.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I am a licensed professional engineer with a degree in Mechanical Engineering from Mississippi State University. I worked for CenterPoint Energy, Inc. ("CenterPoint") for over 15 years in various engineering and operations positions of increasing responsibility. I have experience in the design and execution of natural gas relocation, system improvement, and customer additions projects — including operational oversight of construction and maintenance activities relating to the systems. I also previously held the role of Distribution Integrity Manager overseeing CenterPoint's efforts to comply with applicable integrity management rules and managed the execution of engineering design activities relating to CenterPoint's assets located within the State of Texas. I was hired as the Associate Vice President of Operations for WTGU in February 2024 and promoted to Vice President in June 2024.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I provided testimony before the Railroad Commission of Texas ("Commission") in Gas Utilities Docket ("GUD") No. 10669 and Docket No. OS-23-00015513.

Q. HAVE YOU PRESENTED TESTIMONY IN ANY OTHER REGULATORY PROCEEDINGS?

A. Yes. As Distribution Integrity Manager for CenterPoint, I supported several company programs before the Arkansas Public Service Commission.

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

A. Yes, it was.

Q. ARE YOU SPONSORING OR CO-SPONSORING ANY SCHEDULES?

A. Yes. I am co-sponsoring the following schedules:

B-1 Operations and Maintenance Expense
C-5 Gas Reliability Infrastructure Program Additions
J-3 Pipe Replacement Cost Analysis
J-4 Meter Replacement Cost Analysis

Q. WERE THESE SCHEDULES PREPARED BY YOU, WITH YOUR KNOWLEDGE 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 Jack J. King and Amanda Edgmon who also support the Company's operations and investment.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to describe certain key WTGU field operations and expenses. I also support the Company's request to modify the jurisdictional factors used to determine what portion of the Company's capital investment will be recovered from jurisdictional customers.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the exhibits listed in the table of contents.

II. WTGU'S CONSTRUCTION AND FIELD OPERATIONS

Q. PLEASE PROVIDE A GENERAL DESCRIPTION OF WTGU'S DISTRICT OFFICES.

A. WTGU currently maintains twelve (12) district offices that are located from the Oklahoma Panhandle down to Frio County in South Texas. These offices function as "report-to-duty" stations for district managers, supervisors, field personnel and customer service staff. The Texas district offices are located in Lytle, Junction, Fort Stockton, Kermit, Wolfforth, Lubbock, Shamrock, Canadian, Stratford, Amarillo, Uvalde and Dalhart. The Oklahoma offices are located in Texhoma and Beaver.

Q. PLEASE EXPLAIN WHY WTGU'S DISTRICT OFFICES IN SHAMROCK AND TEXHOMA ARE RESPONSIBLE FOR OPERATIONS IN TWO STATES.

A. Based on their geographic location, it is more efficient and cost effective to assign the Shamrock and the Texhoma offices with responsibility for field operations in both Texas and Oklahoma.

Q. WHAT IS WTGU'S PROCESS TO ENSURE THAT COMPANY OPERATIONS AND MAINTENANCE ("O&M") EXPENSES ARE FAIR, JUST, AND REASONABLE?

A. Each manager is held responsible for the O&M expenses charged to their district. These expenses are reviewed for reasonableness and compared to the prior year performance for the same period. Also, outside of basic inventory (new housing developments, large projects and the Distribution Integrity Management Plan ("DIMP")), WTGU creates a material list for each project and orders all the material packaged and delivered at a reduced cost from our supplier. WTGU also has a "container" program for our regular inventory. Our supplier stocks each container at each district and maintains the inventory. This saves money by ordering volume and distributing it through the districts as opposed to each district ordering single items on a project by project basis (which would cost more).

Q. WHAT IS THE BIDDING PROCESS FOR CONSTRUCTION JOBS?

A. WTGU distributes formal requests for bids on large construction and replacement projects. Interested contractors are given project specifications and an opportunity for a field inspection. After bids are received, WTGU evaluates them, accepts the lowest reasonable bid proposal, and executes a construction contract with the contractor. For smaller projects, WTGU compares informal price quotes from local area suppliers and contractors to ensure that a competitive price is received for goods and services.

Q. HOW DOES WTGU MONITOR CONSTRUCTION PROJECT SPENDING?

A. Before beginning a project, costs are estimated based on historical experience and are submitted for approval to a corporate officer. Each approved project is assigned a project identification number. Costs are accumulated under the project ID number as invoices are received from suppliers and contractors. Accumulated project costs are reviewed on an ongoing basis during construction and, at the completion of the project, they are reviewed against the initial estimated budget.

Q. WHAT ADDITIONAL OVERSIGHT DO YOU HAVE ON OTHER EXPENDITURES?

A. Each district manager must request a purchase order for any non-recurring expenditure (e.g., equipment, inventory, service, tools, maintenance, etc.).

Purchase order requests are reviewed by the appropriate level of leadership for compliance with the defined approval matrix.

Q. WHAT IS WTGU'S PIPELINE SAFETY DIMP PROGRAM?

A. WTGU's DIMP program is a written plan that was developed in compliance with 49 CFR Part 192 - Subpart P. The purpose of the DIMP plan is to gather knowledge of WTGU's distribution systems, identify threats to the systems' integrity, evaluate and rank the risks to the systems, implement measures to address those risks, and evaluate the effectiveness of the plan. WTGU has generated a detailed digital mapping system of its distribution pipeline system and initiated an automated leak tracking system to help monitor the system risks and the plan's effectiveness. WTGU also utilizes a detailed engineering model to evaluate performance and rank the priority of identified risks.

Q. EXPLAIN WTGU'S STEEL LINE REPLACEMENT PROGRAM.

A. Prior to August 1, 2011, 16 Texas Administrative Code § 8.209, required WTGU to submit its risk-based removal or replacement program to the Commission's Pipeline Safety Division. WTGU's risk-based program uses information collected by the DIMP plan to determine a risk ranking of factors threatening the distribution system. Based on the risk analysis, WTGU determines the pipeline segments or facilities posing the highest risk and schedules the replacement of at least 5% of these facilities annually. In 2023, WTGU spent more than $8,000,000 to replace suspect mains and service lines situated primarily within WTGU's older municipal distribution systems serving jurisdictional customers.

Q. WHAT CHANGES HAVE BEEN MADE TO COMPLY WITH PIPELINE SAFETY AND OTHER REGULATORY REQUIREMENTS SINCE WTGU'S LAST RATE CASE?

A. An increased focus on safety has led regulators to raise the Company's required annual percentage of DIMP investment from 5% to 8% per year. This increase materially changed the amount of investment that the Company must make in its system each year. Specifically, WTGU initially identified over 300 miles of pipe that, pursuant to DIMP, is slated for replacement. WTGU had been replacing, on average, approximately 90,000 feet of pipe per year. With the increase in the target percentage to 8%, the Company now targets approximately 143,000 feet in annual DIMP replacement footage at an annual cost of approximately $8,000,000.

Additionally, the Company continues to monitor the changing regulatory environment for additional requirements that may be implemented. For example, currently the Leak Detection and Repair ("LDAR") regulation is under review at a federal level. If passed, this regulation ". . . [would] strengthen leakage survey and patrolling requirements; performance standards for advanced leak detection programs; leak grading and repair criteria with mandatory repair timelines; requirements for mitigation of emissions from blowdowns; pressure relief device design, configuration, and maintenance requirements; and clarified requirements for investigating failures."[1] In the proposed form, operators may experience additional costs. For example, operators may need to purchase new leak detection equipment to comply with the proposed performance standard for that equipment.

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[1] Pipeline Safety: Gas Pipeline Leak Detection and Repair | PHMSA available at https://www.govinfo.gov/content/pkg/FR-2023-05-18/pdf/2023-09918.pdf.

Q. HAVE THERE BEEN ANY OTHER CHANGES IN THE COMPANY'S OPERATIONS OR INVESTMENT PRACTICES SINCE ITS LAST RATE CASE?

A. Yes. The Company has investigated and deployed new technology to ensure continued compliance and efficient operations. For example, the Company has modified its GIS mapping system to allow for the direct entry of field data. Currently, each time a mainline is exposed, the field technician has the opportunity to enter an inspection report – including photographs – directly into the mapping system. This information becomes available to the integrity management team to continue analysis of the threats and risks in the system.

Additionally, the Company is working to pilot the deployment of Automated Meter Reading ("AMR") technology in the City of White Deer. This technology utilizes a cellular network to remotely read meters. Pending the outcome of the pilot deployment, the Company intends to continue deployment of AMR technology more broadly across the service territory. As the technology is more broadly deployed, the Company anticipates more accurate meter reads for customers and increased efficiency in the operations of the natural gas system.

Q. WITH REGARD TO FIELD OPERATIONS, DOES WTGU RELY ON ANY AFFILIATES TO PROVIDE SERVICE TO CUSTOMERS?

A. No.

Q. DO WTGU FIELD PERSONNEL PERFORM SERVICES FOR ANY OF WTGU'S AFFILIATES?

A. WTGU field technicians may occasionally perform activities such as annual patrols, line locating, leak survey, and cathodic protection maintenance for WTG Gas Transmission Company, LLC ("WTGGT"). However, these activities are not performed on a regular basis within any given year.

III. <u>CAPITAL INVESTMENT ISSUES</u>

Q. WHICH WITNESSES SUPPORT THE PRUDENCE OF INVESTMENT IN THE COMPANY'S SYSTEM SINCE THE LAST RATE CASE?

A. Mr. King and I support the prudence of all projects undertaken since Docket No. OS-20-00004347. More specifically, I can address the day-to-day work on the projects at issue in this proceeding, their necessity, and the steps the Company takes to ensure the reasonableness of all project costs. Ms. Edgmon, because she was responsible for making the filings themselves, presents the Company's annual Gas Reliability Infrastructure Program ("GRIP") filings since Docket No. OS-20-00004347.

Q. PLEASE DESCRIBE THE CAPITAL INVESTMENT FOR WHICH THE COMPANY SEEKS A PRUDENCE DETERMINATION IN THIS CASE.

A. The Company continually makes substantial investments in its infrastructure to ensure the safe and reliable provision of gas distribution service to our customers. The Company's capital additions since Docket No. OS-23-00004347 total approximately $61.4 million through December 31, 2023. As shown in Exhibit MSS-1, the main categories of investment were:

- Buildings and Equipment: about $2.4 million was invested in general and other plant;
- DIMP: more than $30 million for DIMP replacement work;
- System Growth: approximately $25 million was for system expansion;
- System Integrity: over $1.8 million was for system and public improvements; and
- Measurement: approximately $1.9 million related to the purchase and installation of meter reading equipment and ERTs (Encoder, Receiver, Transmitters).

Approximately 52% of the total investment represented here is directly related to safety.

Q. IS SOME OF THIS INVESTMENT CURRENTLY BEING RECOVERED THROUGH THE COMPANY'S GRIP RATES?

A. Yes. Some of this investment is currently being recovered through GRIP rates the Commission approved for GRIP filings the Company has made since the Company's last rate proceeding. Following Docket No. OS-20-00004347, WTGU made four GRIP filings, with the most recent one filed on May 17, 2024, to recover capital investment made in 2023.

Q. WHAT HAVE BEEN WTGU'S CAPITAL ADDITIONS BY YEAR SINCE THE LAST RATE CASE?

A. As shown on Exhibit MSS-1, capital additions in Texas since 2019 have been the following:

2020: $18,668,741

2021: $11,741,728

2022: $15,295,068

2023: $15,682,229

The investment amounts noted above have been primarily driven by growth, public improvement projects, and the need to replace aging infrastructure.

Q. SINCE THE LAST RATE CASE, HOW MUCH INVESTMENT HAS THE COMPANY MADE FOR JURISDICTIONAL AND NON-JURISDICTIONAL CUSTOMERS IN TEXAS?

A. As shown in Exhibit MSS-2, since January 1, 2020, the investment has been:

- 84.5% or $51.9 million for Jurisdictional Customers;
- 8.65% or $5.3 million for Non-Jurisdictional customers; and
- 6.85% or $4.2 million for both customer types.

Q. IS THE COMPANY REQUESTING A PRUDENCY DETERMINATION FOR CAPITAL INVESTMENT MADE SINCE 2019?

A. Yes, the Company is requesting a prudency determination on all plant placed in service from January 1, 2020 through December 31, 2023.

Q. IS ALL OF THE CAPITAL INVESTMENT BOOKED TO PLANT AS ADJUSTED THROUGH DECEMBER 31, 2023 USED AND USEFUL IN PROVIDING UTILITY SERVICE?

A. Yes.

Q. IS ALL OF THE COMPANY'S CAPITAL INVESTMENT IN WTGU PRUDENT AND REASONABLY AND NECESSARILY INCURRED?

A. Yes. All of the Company's capital investment in the areas it serves throughout Texas was prudent and was reasonably and necessarily incurred in order to provide a safe and reliable system with an appropriate level of customer service.

Q. ARE YOU AWARE OF THE COMPANY'S USE OF A "JURISDICTIONAL FACTOR" IN ITS GRIP FILINGS?

A. Yes. This was an issue in the Company's last rate case. I understand in the GRIP filings that a "jurisdictional factor" is used to calculate how much of the total incremental capital investment the Company can recover from jurisdictional customers. Ms. Edgmon addresses that issue in detail in her direct testimony and explains the Company's request to revise the way the Company recovers investment from jurisdictional customers.

Q. WHAT IS YOUR UNDERSTANDING OF WHY THE COMPANY WANTS TO CHANGE THE WAY IT RECOVERS INVESTMENT AMOUNTS FROM JURISDICTIONAL CUSTOMERS?

A. Going forward, the Company wants to more closely align recovery of the cost of its investment from the customers who benefit from that investment.

Q. CAN YOU PROVIDE AN EXAMPLE OF CAPITAL INVESTMENT THAT IS MADE SOLELY FOR JURISDICTIONAL CUSTOMERS?

A. Yes. The Company is experiencing significant jurisdictional customer growth within the Lubbock, Amarillo, and San Antonio areas. With this growth, the Company is not only investing in the installation of new mainlines to serve these communities but, also, in reinforcement of the existing distribution system to ensure continued reliability of service to current jurisdictional customers.

Additionally, the Company's DIMP program has been developed to address any risks in the system with the highest risk assets taking priority. In general, a risk assessment is driven by the likelihood of an incident occurring and the consequence should that event occur. The consequence component of the assessment increases as customer density around an asset increases. Therefore, the assets targeted for replacement are generally located where there is higher customer density such as residential areas comprised only of jurisdictional customers in Canadian, Junction, Shamrock, Kermit, or other cities within the operating territory of the Company.

As an example of a recent DIMP project, the replacement of approximately 13,000 feet of mainline in the city of Kermit, Texas serves to ensure the continued safe and reliable delivery of natural gas to the residents of Kermit. The customers taking service from this project are Domestic (or residential) customers. It is reasonable for the Company to fully recover the costs of DIMP projects such as this from jurisdictional customers.

Q. CAN YOU PROVIDE AN EXAMPLE OF CAPITAL INVESTMENT THAT IS MADE FOR BOTH JURISDICTIONAL AND NON-JURISDICTIONAL CUSTOMERS?

A. Yes. As identified in Exhibit MSS-2, there are various capital investments that may benefit both jurisdictional and non-jurisdictional customers. This includes vehicles, equipment, or facility related items. For example, a vehicle purchased in the Dalhart area will be used in the installation and maintenance of assets that benefit both jurisdictional and non-jurisdictional customers.

IV. ADDITIONAL SCHEDULES SPONSORED

Q. DO YOU SPONSOR OR CO-SPONSOR ANY ADDITIONAL SCHEDULES ASSOCIATED WITH THE COMPANY'S RATE FILING PACKAGE?

A. Yes, I co-sponsor Schedules B-1, C-5, J-3, and J-4.

Q. PLEASE DESCRIBE THE SCHEDULE OF PIPE REPLACEMENT COST ANALYSIS (J-3).

A. For its Pipe Replacement Cost Analysis, WTGU used conservative estimates for pipeline materials and construction. Pipeline footages for this analysis come directly off WTGU's Form 7100 filing and DIMP assessment plan. The estimated price-per-foot used in the analysis includes the cost of materials (based on SDR 11 poly pipe or standard wall steel pipe), installation costs based on recent WTGU experience, and minimal right-of-way costs. In the last rate case, Dr. Fairchild used a 1" diameter replacement assumption. This approach, however, does not accurately reflect the diverse makeup of the Company's system, or the fact that the majority of pipe operating is at least 2" in diameter. As such, Dr. Fairchild is using a replacement assumption of 2" diameter pipe, which he addresses in his direct testimony.

Q. PLEASE DESCRIBE THE METER REPLACEMENT COST ANALYSIS (SCHEDULE J-4) THAT WAS MADE A PART OF THE RATE MODEL. EXPLAIN WHERE THE REPLACEMENT COST ESTIMATES CAME FROM AND WHY ORIGINAL COST IS UNAVAILABLE.

A. WTGU's distribution assets are composed of more than fifteen different acquisitions made by WTGU over the past 30-plus years. Most of these assets were previously owned by small municipalities or small, family-owned businesses that did not maintain their original cost historical data. As a result, WTGU cannot provide a complete original cost analysis of its distribution plant.

For its Meter Replacement Cost Analysis, WTGU used conservative replacement cost estimates for the four primary types of customer meter settings. These estimates include the cost of the service rider and meter run including any regulation, valves, and fittings. More specifically:

- Residential – these are low-volume positive displacement meters, typically represented by AL-175 or Rockwell 200 type meters;
- Small Commercial – these are higher volume positive displacement meters, typically represented by AL-800 or Rockwell 750 type meters;
- Irrigation – the same positive displacement meter type used in Small Commercial applications or, for larger irrigation customers, a Roots rotary type meter is installed; and
- Large Commercial – these meter sets are usually connected with high volume turbine and ultrasonic type meters or an orifice meter run tied to an electrical measurement unit (Total Flow).

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF TEXAS §
§
COUNTY OF MIDLAND §

AFFIDAVIT OF MATTHEW S. SMITH

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

1. "My name is Matthew S. Smith. I am over the age of eighteen (18) and fully competent to make this affidavit. The facts stated herein are true and correct based on my personal knowledge. My current position is Vice President of Operations for West Texas Gas Utility, LLC.
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.

Matthew S. Smith

Matthew S. Smith

SUBSCRIBED AND SWORN TO BEFORE ME by the said Matthew S. Smith on this 26th day of June 2024.

Jamie A Mead

Notary Public, State of Texas

JAMIE A. MEAD
Notary Public, State of Texas
Comm. Expires 03-22-2026
Notary ID 133659307

Texas Specific Allocations by Category

Sum of Texas Allocated Cost	Year				
Project Reason	**2020**	**2021**	**2022**	**2023**	**Grand Total**
Buildings and Equipment	**889,713**	**762,027**	**607,080**	**113,675**	**2,372,495**
Buildings			39,080	7,473	46,553
Communication Equipment	42,766	4,098	14,329	18,201	79,394
Equipment	786,775	631,869	454,817	-	1,873,460
Field Equipment	57,576	104,680	94,563	88,001	344,820
Office Equipment	2,596	21,380	4,292	-	28,268
DIMP	**8,127,602**	**6,406,477**	**8,095,442**	**7,755,979**	**30,385,499**
DIMP	8,127,602	6,406,477	8,095,442	7,755,979	30,385,499
System Growth	**9,345,555**	**4,251,279**	**5,006,646**	**6,338,935**	**24,942,415**
System Growth	9,345,555	4,251,279	5,006,646	6,338,935	24,942,415
System Integrity	**107,182**	**181,063**	**922,123**	**595,910**	**1,806,278**
System Integrity	107,182	181,063	922,123	595,910	1,806,278
Measurement	**198,689**	**140,882**	**663,777**	**877,730**	**1,881,078**
Measurement	198,689	140,882	663,777	877,730	1,881,078
Land	**-**				**-**
Land	-				-
Grand Total	**18,668,741**	**11,741,728**	**15,295,068**	**15,682,229**	**61,387,766**

Texas Specific Utilities Investment

Customers Benefitted	Sum of Texas Allocated Cost			Texas Investment		
Jurisdictional	$	51,876,893		$	51,876,893	84.51%
Non-Jurisdictional	$	5,308,143		$	5,308,143	8.65%
Both	$	4,202,729		$	4,202,729	6.85%
Grand Total	**$**	**61,387,766**		**$**	**61,387,766**	**100.00%**

WORKPAPERS

TO

DIRECT TESTIMONY

OF

MATTHEW S. SMITH, P.E.

Workpapers to the Direct Testimony of Matthew S. Smith, P.E. are being provided in electronic format.

CASE NO. 00017816

STATEMENT OF INTENT OF WEST TEXAS GAS, INC. TO INCREASE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF TEXAS	§ § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

DANE A. WATSON, PE, CDP

ON BEHALF OF

WEST TEXAS GAS UTILITY, LLC

July 16, 2024

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LIST OF EXHIBITS

EXECUTIVE SUMMARY OF DANE A. WATSON, PE, CDP

I have performed a depreciation study of West Texas Gas Utility, LLC ("WTGU" or the "Company") based on the depreciable plant in service on December 31, 2023. The results of my depreciation study support an annualized depreciation expense for WTGU of approximately $5.9 million. This represents a decrease of approximately $769,000 over the annualized depreciation expense calculated on year-end 2023 investment using the current depreciation rates on a system-wide basis. A table summarizing the proposed versus existing accrual by function is shown below.

Utility Function	Plant Balance at 12/31/2023	Existing Annual Accrual	Proposed Annual Accrual	Difference
Total Intangible Plant	$ 378,315	$ -	$ -	$ -
Total Gathering Plant	3,148,811	-	-	-
Total Transmission Plant	52,329,558	1,317,333	1,165,158	(152,176)
Total Distribution Plant	176,288,117	4,609,377	4,074,103	(535,274)
Total General Plant	16,317,866	740,142	677,272	(62,871)
Amortized Reserve Difference			(18,292)	(18,292)
Grand Total	$ 248,462,667	$ 6,666,853	$ 5,898,241	$ (768,612)

Detailed information regarding the service life and net salvage characteristics that support my proposed depreciation rates can be found in the depreciation study included as Exhibit DAW-1 of my testimony, as well as in my workpapers.

DIRECT TESTIMONY OF DANE A. WATSON

I. POSITION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BY WHOM YOU ARE EMPLOYED.

A. My name is Dane A. Watson. I am a Partner of Alliance Consulting Group. Alliance Consulting Group provides consulting and expert services to the utility industry.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am filing testimony on behalf of WTGU.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Arkansas at Fayetteville and a master's degree in Business Administration from Amberton University.

Q. DO YOU HOLD ANY SPECIAL CERTIFICATION AS A DEPRECIATION EXPERT?

A. Yes. The Society of Depreciation Professionals ("SDP") has established national standards for depreciation professionals. The SDP administers an examination and has certain required qualifications to become certified in this field. I met all requirements and hold a Certified Depreciation Professional certification.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. Since graduating from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance Consulting Group in 2004 and am responsible for conducting depreciation, valuation, and certain accounting-related studies for clients in various industries. My duties related to depreciation studies include the assembly and analysis of historical and simulated data, conducting field reviews, determining service life and net salvage estimates, calculating annual depreciation, presenting recommended depreciation rates to utility management for its consideration, and supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with Texas Utilities Electric Company and successor companies ("TXU"). During my tenure with TXU, I was responsible for, among other things, conducting valuation and depreciation studies for the domestic TXU companies. During that time, I served as Manager of Property Accounting Services and Records Management in addition to my depreciation responsibilities.

I have twice been Chair of the Edison Electric Institute ("EEI") Property Accounting and Valuation Committee and have been Chairman of EEI's Depreciation and Economic Issues Subcommittee. I am a Registered Professional Engineer in the State of Texas. I am a Senior Member of the Institute of Electrical and Electronics Engineers ("IEEE") and served for several years as an officer of the Executive Board of the Dallas Section of IEEE. I am also a twice Past-President of the Society of Depreciation Professionals.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. In my 35-year career, I have conducted depreciation studies, filed written testimony, and/or testified in 260 cases before more than thirty-five different state and regulatory agencies across the United States. I have testified in more than 20 separate proceedings before the Railroad Commission of Texas ("Commission"). A list of my appearances is shown in Exhibit DAW-2. I have also appeared in

Federal Energy Regulatory Commission Docket No. 02-7-00 as an industry panelist on asset retirement obligations.

II. PURPOSE AND SUMMARY OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. I sponsor and support the depreciation study performed for WTGU and its natural gas assets. The depreciation study attached as Exhibit DAW-1 produces the depreciation rates used to determine the depreciation expense for the WTGU assets included in this filing.

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

A. Yes. I have prepared or supervised the preparation of the exhibits listed in the table of contents.

Q. WHAT DEPRECIATION EXPENSE ARE YOU RECOMMENDING IN THIS PROCEEDING FOR WTGU?

A. Based on the depreciation study, which analyzed the Company's depreciable plant in service at December 31, 2023, I recommend an annualized depreciation expense of approximately $5.9 million. This represents a decrease of approximately $769,00 over the annualized depreciation expense calculated on investment as of December 31, 2023, using the existing depreciation rates approved by this Commission in open settlement Docket No. OS-20-00004347, formerly Gas Utilities Docket ("GUD") No. 10998.

Q. WHAT ARE THE PRIMARY FACTORS THAT HAVE INFLUENCED THE CHANGE IN THE COMPANY'S DEPRECIATION RATES?

A. The primary factors that influenced the change in depreciation rates for WTGU are changes to average service lives and historical accumulated depreciation reserve levels.

Q. DOES THE DEPRECIATION STUDY YOU SPONSOR IN THIS CASE REFLECT THE MOST CURRENT DATA AVAILABLE FOR WTGU ASSETS?

A. Yes. The data used reflects the most recent experience and future expectations for life and net salvage characteristics for WTGU assets.

III. <u>WEST TEXAS GAS DEPRECIATION STUDY</u>

A. Summary of the Depreciation Study Results

Q. DID YOU PREPARE THE WTGU DEPRECIATION STUDY?

A. Yes. The WTGU Study is attached to my testimony as Exhibit DAW–1. The study in Exhibit DAW-1 analyzes the life and net salvage percentage for the property groups associated with the Texas intangible, gathering, transmission, distribution and general plant assets of WTGU at December 31, 2023.

Q. WHAT PROPERTY IS INCLUDED IN THE DEPRECIATION STUDY?

A. There are five general classes, or functional groups, of depreciable property: Intangible Plant, Gathering Plant, Transmission Plant, Distribution Plant, and General Plant property. Intangible Plant includes software and related assets. Other intangible assets such as organization costs, franchises, and acquisition adjustments were excluded from the study. Gathering Plant assets collect gas from natural gas producers who wish to market their gas. Transmission Plant takes the natural gas using intermediate pressure to send gas to the Distribution System. The Distribution Plant functional group primarily consists of pipes and associated facilities used to distribute gas within the cities served by the Company. General Plant property is not location-specific but is used to support the overall distribution of gas to customers. Fully depreciated compressor station equipment and non-depreciable property, such as land, were excluded from the study.

Q. ARE THE RESULTS OF YOUR DEPRECIATION STUDY REFLECTED IN THE TEST YEAR ENDING DECEMBER 31, 2023 COST OF SERVICE CALCULATION?

A. Yes. The cost of service calculation for depreciation expense applies my recommended depreciation rates to the adjusted plant balances as of December 31, 2023.

Q. WHEN DID THE LAST CHANGE IN THE COMPANY'S DEPRECIATION RATES OCCUR?

A. The current depreciation rates were established in Docket No. OS-20-00004347 and were based on an amended unanimous settlement agreement between the Company and intervenors in Docket No. OS-20-00004347, and authorized in the Final Order signed by the Commissioners on February 9, 2021.[1]

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[1] *Statement of Intent of West Texas Gas, Inc. to Increase Gas Utility Rates Within the Unincorporated Areas of Texas*, Docket No. OS-20-00004347 consol. (formerly GUD No. 10998), Final Order (Feb. 9, 2021).

B. Overview of Depreciation Study

Q. WHAT DEFINITION OF DEPRECIATION HAVE YOU USED FOR PURPOSES OF CONDUCTING A DEPRECIATION STUDY AND PREPARING YOUR TESTIMONY?

A. The term "depreciation," as used herein, is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. Depreciation is a process of allocation, not valuation. Depreciation expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. Thus, depreciation is considered an expense or cost, rather than a loss or decrease in value. The Company accrues depreciation based on the original cost of all property included in each depreciable plant account. On retirement, the full cost of depreciable property, less the net salvage amount, if any, is charged to the depreciation reserve.

Q. PLEASE DESCRIBE YOUR APPROACH TO PERFORMING A DEPRECIATION STUDY.

A. I conducted the depreciation study in four phases as shown in my Exhibit DAW-1. The four phases are: Data Collection, Analysis, Evaluation, and Calculation. During the initial phase of the study, I collected historical data to be used in the analysis. After the data was assembled, I performed analyses to determine the life and net salvage percentages for the different property groups being studied. As part of this process, I conferred with field personnel responsible for the installation, operation, and removal of the assets to gain their input into the operation, maintenance, and salvage of the assets. The information obtained from field personnel, combined with the study results, was then evaluated to determine how the results of the historical asset activity analysis, in conjunction with the Company's expected future plans, should be applied. Using all of these resources, I then calculated the depreciation rate for each function.

Q. WHAT DEPRECIATION METHODOLOGY DID YOU USE?

A. The straight-line, Equal Life Group ("ELG") remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. The ELG remaining-life depreciation system was also used to develop the depreciation rates currently in place. The ELG methodology has been an approved depreciation methodology at the Commission for over 20 years.[2] And it continues to be adopted for Texas natural gas utilities in more recent proceedings.[3]

Q. HOW WERE DEPRECIATION RATES DETERMINED USING THE ELG PROCEDURE?

A. In this procedure, the annual depreciation expense for each group is computed by dividing the original cost of the asset, less allocated depreciation reserve, plus or minus estimated net salvage, by its respective equal life group remaining life. The resulting annual accrual amounts of all depreciable property within a function is

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[2] *Statement of Intent filed by Lone Star Gas Company and Lone Star Pipeline Company, Divisions of Enserch Corporation, and ENSAT Pipeline Company to Increase the Intracompany City Gate Rate Established in GUD 3543*, GUD No. 8664, Second Order on Rehearing Nunc Pro Tunc at Finding of Fact ("FoF") No. 92 (Nov. 25, 1997).

[3] *Statement of Intent to Change the Rates CGS and Rate PT Rates of Atmos Pipeline–Texas*, GUD No. 10580, Final Order at FoF No. 63 (Aug. 1, 2017); *Statement of Intent filed by CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas, to Increase Rates in the Beaumont/East Texas Division*, GUD No. 10920 consol., Final Order (Jun. 16, 2020).

accumulated, and the total is divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates are based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual functional depreciation rates are shown in Exhibit DAW-1, Appendix A. The remaining life calculations are discussed below and are shown in Exhibit DAW-1, Appendix A-1.

C. Service Lives

Q. WHAT IS THE SIGNIFICANCE OF AN ASSET'S USEFUL LIFE IN YOUR DEPRECIATION STUDY?

A. An asset's useful life is used to determine the remaining life over which the remaining cost (original cost plus or minus net salvage, minus accumulated depreciation) can be allocated to normalize the asset's cost and spread ratably over future periods.

Q. WHAT ISSUES DID YOU FIND WITH WTGU ASSETS IN ESTIMATING SERVICE LIFE?

A. WTGU has added most of its plant through acquisition of assets from other natural gas companies. When assets are acquired by WTGU, the asset is booked with a vintage year of the acquisition date. Acquiring assets a portion of the way through their lives and the recording of the vintages of those assets as the year of acquisition has an impact on the depreciable life of the asset groups. The result is that the asset will have a shorter book life than it will operationally. In other words, assets acquired that are 30 years old will appear to be new in the Company's accounting system. As such a 60-year total life for the assets will only carry a 30-year life for depreciation purposes.

Q. WILL ASSETS FOR WTGU HAVE SERVICE LIVES SIMILAR TO OTHER NATURAL GAS COMPANIES?

A. No. The lives of assets for WTGU will be shorter than other natural gas companies who have in-service dates equal to the year of installation. For WTGU, an asset acquired in 2012 will reflect an installation year of 2012, even though the asset may have an original in-service year many years earlier than the acquisition year. With that in mind, the age at acquisition will reduce the life of WTGU assets as compared to the lives of similar assets in other companies where the vintage and the original in-service dates match.

Q. WHAT LIFE DO YOU RECOMMEND FOR THE TWO LARGEST ACCOUNTS, 367 (TRANSMISSION MAINS) AND 376 (DISTRIBUTION MAINS)?

A. I recommend increasing to a 50-year life and a R2 curve for both Account 367 Transmission Mains and Account 376 Distribution Mains. Given the assets are, in reality, much older (20-30 years) than the vintage year, the proposed lives are a reasonable proxy for future expectations in these accounts. For example, the average age of current investment in account 367, using the acquisition year as the vintage, is 11.9 years. Operational per foot data provided by the Company shows the average physical age of existing steel mains is approximately 47 years using a mileage weighting (which will be somewhat longer than a dollar-weighted average). The Operational life of a steel transmission main is longer than 50 years.

However, the 50-year proposed average service life incorporates the full period of time in which the company will have to depreciate the assets on its books before the assets physically retire. Graphs of the proposed curves are found in Exhibit DAW-1 in the life analysis section and discussed further for each account.

Q. HOW DID YOU DETERMINE THE AVERAGE SERVICE LIVES FOR EACH ACCOUNT?

A. The establishment of appropriate average service lives for each account was determined by using the actuarial life analysis method, discussions with Company personnel, and professional judgment. The remaining life, by account, is calculated in Appendix A-1 of my Exhibit DAW-1. Graphs and tables supporting the actuarial analysis along with the chosen Iowa Curves used to determine the average service lives for analyzed accounts are found in the Life Analysis section of Exhibit DAW-1.

Q. PLEASE SUMMARIZE THE RESULTS OF THE WTGU STUDY WITH RESPECT TO AVERAGE SERVICE LIVES.

A. Table 1 below shows the existing and proposed average service lives and selected curve for each account.

		Existing		Proposed	
Account	**Description**	**Life**	**Curve**	**Life**	**Curve**
303	Intangible Plant	17	SQ	15	SQ
332	Field Lines	45	R3	45	R3
334	Field Measuring & Regulating Equip	36	R4	36	R4
365.2	Land Rights	45	SQ	45	SQ
367	Transmission Mains	45	R2	50	R2
369	Measuring and Regulating Equipment	40	R4	40	R4
369.1	Meters and Regulators	40	R4	40	R4
371	Other Equipment	20	R5	15	R4
376	Distribution Mains	45	R3	50	R2
378	Distribution Measuring and Regulating Equipment	25	R3	36	R5

		Existing		Proposed	
Account	Description	Life	Curve	Life	Curve
378.1	Meters			20	R2
387	Other Equipment	23	S4	23	S4
389	General Plant Land Rights	45	SQ	50	SQ
390	Structures and Improvements	25	R2.5	50	R0.5
391	Office Furniture and Equipment	20	SQ	20	SQ
391.1	Computer Equipment	5	SQ	5	SQ
392	Transportation Equipment	8	L2	6	L2
394	Tools, Shop, and Garage Equipment	25	L2	25	SQ
396	Power Operating Equipment			20	L2
397	Communication Equipment	15	SQ	12	SQ
398	Miscellaneous Equipment	15	SQ	15	SQ

Q. WHAT PROCESS HAVE YOU UNDERTAKEN TO GIVE EFFECT TO BOTH HISTORICAL DATA AND COMPANY-SPECIFIC EXPECTATIONS IN DEVELOPING YOUR SERVICE LIFE RECOMMENDATIONS?

A. In order to achieve a reasonable balance between these critical components of the life analysis, I evaluated the statistical historical data and then applied informed judgment to make the most appropriate service life selections. The objective in any depreciation study is to project the remaining cost (installation, material, and removal cost) to be recovered and the remaining periods over which to recover the costs. This necessarily requires that the service life selections reflect both the Company's historic experience and its current expectations of asset lives. In order to understand the Company's expectations regarding asset lives, I interviewed Company engineers working in both operations and maintenance to confirm the historical activity and indications, current and future plans, expectations, and the applicability to the future surviving assets. The interview process provides important information regarding changes in materials, operation and maintenance, as well as the Company's current expectation regarding the service life of the assets currently in use. This information is then considered along with the historical statistical data to develop the most reasonable and representative expected service lives for the Company's assets. The result of this analysis is reflected in the service life recommendations set forth in my depreciation study.

Q. AS PART OF YOUR DEPRECIATION ANALYSIS, HAVE YOU TAKEN ANY ACTION TO PROPERLY ALIGN WTGU'S DEPRECIATION RESERVE WITH THE LIFE CHARACTERISTICS OF THE INTANGIBLE, GATHERING, DISTRIBUTION, TRANSMISSION AND GENERAL PLANT FUNCTIONS?

A. Yes. In the process of analyzing the Company's depreciation reserve, I observed that the depreciation reserve positions of the various accounts needed to be re-balanced based on my recommended service lives. To allow the relative reserve positions of each account within a function to mirror the life characteristics of the underlying assets, I reallocated the depreciation reserves for all accounts within each function.

Q. WHY IS IT NECESSARY TO RE-ALLOCATE THE RESERVES TO ACCOUNT FOR ANY RECOMMENDED CHANGES IN THE LIFE PARAMETERS?

A. The purpose of a depreciation study, and specifically the remaining life technique used in this case, is to calculate accrual rates that will allow the Company to recover the remaining balance of its investment in plant over the remaining lives of the un-depreciated assets in its invested plant balance. When new service lives or net salvage ratios are adopted as part of a new depreciation study or operational changes occur over time that affect the balances in the reserve, the reserve for individual accounts can become out of sync with the underlying assets. Re-allocation is performed to re-spread the reserves between accounts within a function to bring the reserves for each account back into parity with each other. This brings the undepreciated plant balances associated with each account back in line so that each account contributes the appropriate level of depreciation expense in order to fully depreciate the assets at the end of the recommended useful life.

Q. IS RESERVE RE-ALLOCATION CONSISTENT WITH STANDARD DEPRECIATION PRACTICE AND METHODOLOGIES YOU HAVE USED TO CONDUCT DEPRECIATION STUDIES BEFORE THIS COMMISSION IN THE PAST?

A. Yes. The practice of depreciation reserve allocation is widely recognized and commonly practiced as part of a comprehensive depreciation study for the purposes of setting regulated rates where changes in service lives result in an imbalance between the theoretical and book reserve.[4] With respect to WTGU, my depreciation study demonstrates that there have been significant changes in the life of the property since the last depreciation study.[5] These changes have created imbalances between the theoretical and the book reserve for various accounts within each function making the reallocation of the depreciation reserve appropriate in this instance.

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[4] *Public Utility Depreciation Practices*, National Association of Regulatory Utility Commissioners ("NARUC") (1968), at 48; *Public Utility Depreciation Practices*, NARUC (1996), at 188.

[5] Docket No. OS-20-00004347 was based on plant activity through year end 2019. This study is based on plant activity through year end 2023, thus including an additional four years of data.

Q. DOES THE REALLOCATION CHANGE THE AMOUNT OF THE BOOK RESERVE?

A. No. The recorded book reserve is maintained at a functional level. The reallocation occurs within the accounts of each respective function.

Q. WILL THE COMPANY RECORD THE REALLOCATED RESERVES ON ITS BOOKS?

A. Yes, the book reserves will be reallocated at the time the Commission-approved rates and parameters go into effect. This timing ensures that the Commission's decisions on the life, dispersion and net salvage parameters are fully reflected in the Company's books and records.

D. Net Salvage

Q. WHAT IS NET SALVAGE?

A. As discussed more fully in Exhibit DAW-1, net salvage is the difference between the gross salvage (what is received in scrap value for the asset when retired) and the removal cost (cost to remove and dispose of the asset). Salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset. When salvage exceeds removal cost (positive net salvage), the net salvage reduces the amount to be depreciated over time. When removal cost exceeds salvage (negative net salvage), the negative net salvage increases the amount to be depreciated.

Q. DOES WTGU HAVE ANY NET SALVAGE REFLECTED IN ITS EXISTING DEPRECIATION RATES?

A. Yes, but only for Account 392 Transportation Equipment. Currently, the Company is booking removal cost as part of the cost of a new asset. We recommend that

WTGU change its accounting practice and record cost of removal and gross salvage to the depreciation reserve, similar to other regulated natural gas utilities. The Company has consistently recorded net salvage costs for Account 392 Transportation Equipment. Given the current accounting practice for WTGU, this study recommends 0% net salvage at this time for all accounts except Account 392 and Account 396, which reflect a positive gross salvage.

Q. WHAT ARE YOUR NET SALVAGE RECOMMENDATIONS IN THIS PROCEEDING?

A. As mentioned above, there is no cost of removal or salvage being recorded in the majority of the accounts. However, I have recommended retaining a positive 10% net salvage for Account 392 Transportation Equipment and recommend using the same positive 10% for newly created Account 396 Power Operating Equipment. The detailed analysis of historical net salvage activity in Account 392 is shown in Appendix D of Exhibit DAW-1 and discussed in the Net Salvage section of the report.

IV. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. The depreciation study and analysis performed under my supervision fully support setting depreciation rates at the level I have indicated in my testimony and exhibits. The Company should continue to periodically review the annual depreciation rates for its property. In this way, all customers will be charged for their appropriate share of the capital expended for their benefit. The depreciation study included as Exhibit DAW-1 describes the extensive analysis performed and the resulting rates that are now appropriate for Company property. The Company's depreciation rates should be set at my recommended amounts in order to recover the Company's total investment in property over the estimated remaining life of the assets.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF TEXAS §
§
COUNTY OF COLLIN §

AFFIDAVIT OF DANE A. WATSON

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

1. "My name is Dane A. Watson. I am over the age of eighteen (18) and fully competent to make this affidavit. The facts stated herein are true and correct based on my personal knowledge. I am a Partner of Alliance Consulting Group.
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.

Dane A. Watson

Dane A. Watson

SUBSCRIBED AND SWORN TO BEFORE ME by the said Dane A. Watson on this 9th day of July 2024.

Teresa Stewart

Notary Public, State of Texas

NOTARY PUBLIC STATE OF TEXAS
TERESA STEWART
Notary ID #132275553
My Commission Expires
December 6, 2027

WEST TEXAS GAS

Book Depreciation Accrual Rate Study At December 31, 2023

ALLIANCE
CONSULTING GROUP

WEST TEXAS GAS
DEPRECIATION RATE STUDY

EXECUTIVE SUMMARY

West Texas Gas ("WTG" or "Company") engaged Alliance Consulting Group to conduct a depreciation study of the Company's Gas Intangible, Gathering, Transmission, Distribution, and General utility plant depreciable assets as of December 31, 2023. This study incorporates the same group accounting method used in the previous study and approved in open settlement OS-20-00004347, formerly GUD No. 10998.

I conducted this study using a traditional depreciation study approach for life and net salvage adjusted to take into account that many of the Company's assets were recently acquired and the original in service date was not available upon acquisition. The fixed assets were recorded using the acquisition date as the vintage of investment. I used the straight line, equal life group, remaining life depreciation system. This methodology is a standard methodology used and adopted by the Railroad Commission of Texas as precedent for more than 20 years.

This study recommends an overall decrease of $769 thousand compared to the annual depreciation expense calculated using the existing depreciation rates. The primary drivers of this change are changes to the average service lives, including the increase in average service life in the Company's largest account, Account 378 Distribution Mains, mitigated by the historical accumulated depreciation reserve position in several accounts. A detailed comparison of the existing versus proposed annual accrual rates and amounts is shown in Appendix B.

WEST TEXAS GAS
DEPRECIATION RATE STUDY
AT December 31, 2023

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PURPOSE

The purpose of this study is to develop depreciation rates for the depreciable gathering, transmission, distribution, and general utility property as recorded on the books of West Texas Gas ("WTG" or "Company") as of December 31, 2023. The depreciation rates are designed to recover the total remaining undepreciated investment, adjusted for net salvage, over the remaining life of West Texas Gas' property on a straight-line basis. Fully depreciated compressor station equipment and non-depreciable assets, such as land, were excluded from this study.

West Texas Gas provides local gas distribution service to customers in Texas and Oklahoma. West Texas Gas headquarters are located at 303 Veterans Airpark Ln, Suite 5000, Midland, Texas 79705. WTG has core businesses in natural gas distribution operations, natural gas transmission services, gas gathering/processing, and natural gas liquids transmission services. WTG owns and operates approximately 6,000 miles of Natural Gas Distribution mainlines and serves approximately 29,000 customers within the states of Texas and Oklahoma. WTG also owns and operates approximately 752 miles (non-contiguous) of Natural Gas Transmission pipelines and 143 miles of gathering pipelines within the states of Texas and Oklahoma.

STUDY RESULTS

Recommended depreciation rates for West Texas Gas Texas depreciable property are shown in Appendix A. These rates translate into an annual depreciation accrual for Intangible, Gathering, Transmission, Distribution and General plant of approximately $5.9 million, which is a decrease of $769 thousand when compared to the annual accrual using the existing depreciation rates. These accruals are based on WTG Texas' depreciable investment at December 31, 2023. A table summarizing the proposed versus existing accrual by function is shown below.

Utility Function	Plant Balance at 12/31/2023	Existing Annual Accrual	Proposed Annual Accrual	Difference
Total Intangible Plant	$ 378,315	$ -	$ -	$ -
Total Gathering Plant	3,148,811	-	-	-
Total Transmission Plant	52,329,558	1,317,333	1,165,158	(152,176)
Total Distribution Plant	176,288,117	4,609,377	4,074,103	(535,274)
Total General Plant	16,317,866	740,142	677,272	(62,871)
Amortized Reserve Difference			(18,292)	(18,292)
Grand Total	$ 248,462,667	$ 6,666,853	$ 5,898,241	$ (768,612)

Appendix A shows the detailed computation of the proposed annual accrual rates and amounts for each account. Appendix A-1 shows the calculation of the remaining life for each account. Appendix B shows a comparison of the current versus proposed annual accrual amounts and rates. Appendix C shows the life parameters for each account. Appendix D shows the Transportation net salvage analysis.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. At retirement, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

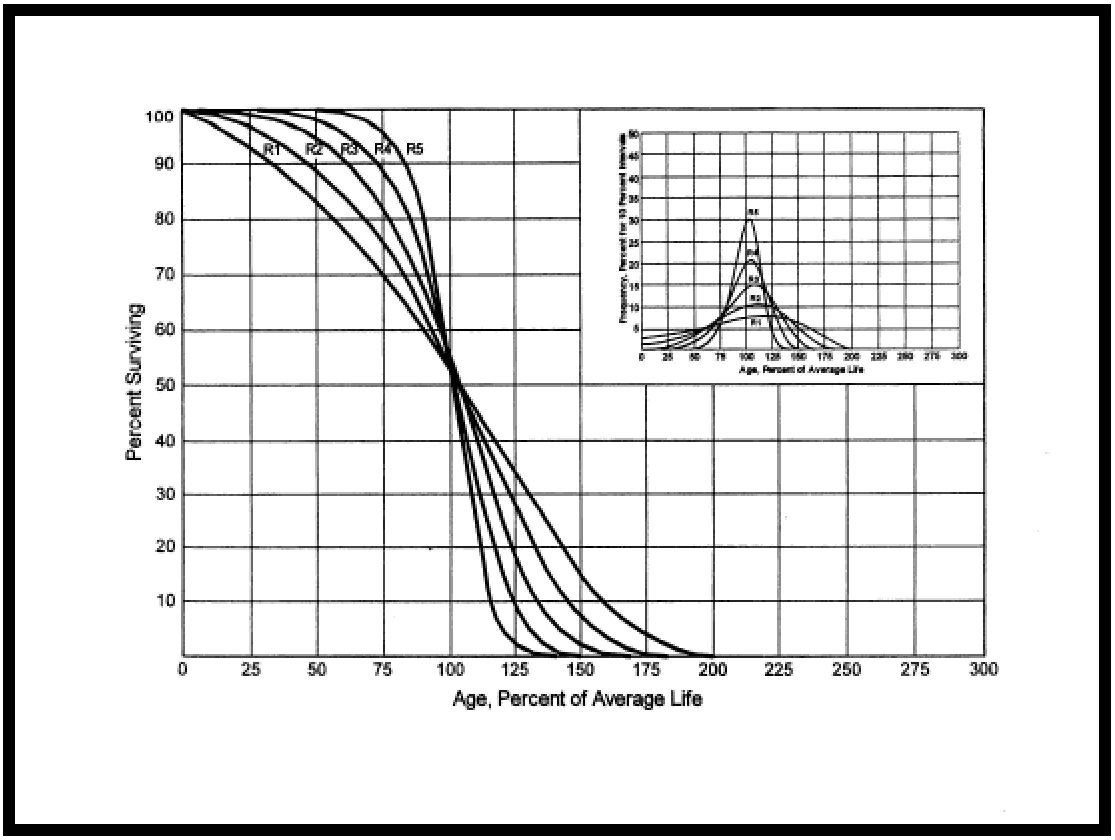
Basis of Depreciation Estimates

Annual and accrued depreciation were calculated in this study by the straight-line, equal life group, remaining-life depreciation system. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset group (less allocated depreciation reserve less estimated net salvage) by its respective average remaining life. The resulting annual accrual amounts were divided by the original cost of the depreciable property in each account to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group, and were computed in a direct weighting by multiplying each vintage or account balance times its remaining life and dividing by the plant investment in service at December 31, 2023. The computations of the annual depreciation rates are shown in Appendix A, and the weighted remaining life calculations are also shown in Appendix A-1. Actuarial Analysis was used with each account within a function where sufficient activity occurred within the account, and judgment was used to some degree on all accounts.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual assets within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by comparing actual experience against various survivor curves. A survivor curve represents the percentage of property remaining in service at various age intervals. The most widely used set of representative survivor curves are the Iowa Survivor Curves (Iowa Curves). The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the twentieth century. Through common usage, revalidation, and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.

There are four families in the Iowa Curves which are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. The four families are designated as “R”— Right, “S” — Symmetric, “L” — Left, and “O” — Origin Modal. First, for distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of “R” moded curves is shown below.



Second, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. Third, an "L" designation (i.e., Left modal) is used for the family whose mode age is less than the average life. Fourth, a special case of left modal dispersion is the "O" or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency) while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

For Intangible, Gathering, Transmission, Distribution, and General

Property accounts, a survivor curve pattern was selected based on analyses of historical data, as well as other factors, such as general changes relevant to the Company's operations. The blending of judgment concerning current conditions and future trends, along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern. Iowa Curves were used to depict the estimated survivor curves for each account.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data were available and sufficient retirement activity was present. Historical data from WTG's Texas and Oklahoma operations were combined for life analysis. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Many accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. Matching data in observed life tables for each experience and placement band to an Iowa Curve requires visual examination. As stated in Depreciation Systems by Wolf and Fitch, "the analyst must decide which points or sections of the curve should be given the most weight. Points at the end of the curve are often based on fewer exposures and may be given less weight than those points based on larger samples" (page 46). Some analysts chose to use mathematical fitting as a tool to narrow the population of curves using a least squares technique. Use of the least squares approach does not imply a statistical validity, however, because the underlying data does not meet criteria for independence between vintages and the same average price for property units through time. Thus, Depreciation Systems cautions, "… the results of mathematical fitting should be checked visually and the final determination of best fit made by the analyst" (page 48). This study uses the visual matching approach to match Iowa Curves, since mathematical fitting produces theoretically possible curve matches. Visual examination and experienced judgment allow the depreciation professional to make the final determination as to the best curve type. Detailed information for each account is shown later in this study and in workpapers.

Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. In this depreciation study, judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, property mix in accounts or a multitude of other considerations that affect the analysis (potentially in various directions), judgment is used to take all of these considerations and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one consideration in these cases may have a substantial impact on the analysis, but overall, the collective effect of these considerations may shed light on the use and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. The establishment of appropriate average service lives and retirement dispersions for the Intangible, Gathering, Transmission, Distribution and General accounts requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed while conducting actuarial life analysis. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

Equal Life Group Depreciation

The Company's existing depreciation rates were calculated using the equal life group procedure. The Railroad Commission of Texas has recognized the precedent of the equal life group ("ELG") depreciation procedure since the late 1990s. Texas gas distribution companies have approved depreciation rates based on the ELG procedure. This study continues to use the ELG depreciation procedure to group the assets within each account. After an average service life and dispersion were selected for each account, those parameters were used to estimate what portion of the surviving investment of each vintage was expected to retire. The depreciation of the group continues until all investment in the vintage group is retired. ELG groups are defined by their respective account dispersion, life, and salvage estimates. A straight-line rate for each ELG group is computed and accumulated across each vintage. The resultant rate for each ELG group is designed to recover all retirements less net salvage as each vintage retires. The ELG procedure recovers net book cost over the life of each ELG group rather than averaging many components. It also closely matches the concept of component or item accounting found in accounting textbooks.

Theoretical Depreciation Reserve

This study used a reserve model that relied on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The equal life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each-year until all property within the vintage is retired. Estimated average service lives and dispersion determine the amount within each equal life group. The equal life group-remaining-life theoretical reserve ratio (RRELG) is calculated as:

$$RRELG = 1 - \frac{(ELG\ Remaining Life)}{(ELG\ Life)} * (1 - Net\ Salvage Ratio)$$

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis was evaluated. After the first three stages were complete, the fourth phase began. This phase involved the calculation of depreciation rates and documenting the corresponding recommendations.

During the Phase I data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting it and comparing to multiple financial system sources: Fixed Asset System (continuing property ledger) and the General Ledger. This data was validated against historical data from prior periods, historical general ledger sources, and through field personnel discussions. This data was reviewed extensively so that it could be put in the proper format for a depreciation study. Also as part of the Phase I data collection process, discussions were conducted with engineers and field operations personnel to obtain information that would be helpful in formulating life recommendations in this study. One of the most important elements in performing a proper depreciation study is to understand how the Company utilizes assets and the environment in which those assets are used. Understanding industry and geographical norms for mortality characteristics are important factors in selecting life and salvage recommendations; however, care must be used not to apply them rigorously to any particular company since no two companies would have the same exact forces of retirement acting upon their assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is helpful when evaluating the output from the life program in relation to the Company's actual asset utilization and environment. Information that was gleaned in these discussions is found both in the Detailed Discussion portions of the Life Analysis section and also in the workpapers. In addition, Alliance personnel possess a significant understanding of the property and its forces of retirement due to years of day-to-day exposure to gas utility property and its operation. Phase 2 is where the actuarial life analysis was performed. Phase 2 and Phase 3 (to be discussed in the next paragraph) overlap to a significant degree. The detailed property records information was used in Phase 2 to develop observed life tables for life analysis and actuarial graphs and statistics. This information was then carried forward into Phase 3 for the evaluation process.

Phase 3 is the evaluation process, which synthesized analysis, interviews, and operational characteristics into a final selection of asset lives. The historical analysis from Phase 2 was further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in Phase 1. The preliminary results were then reviewed and discussed with accounting and operations personnel. Phases 2 and 3 validated the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[1] documents the steps used in conducting this study. Depreciation Systems[2] on page 289 documents the same basic processes in performing a depreciation study.

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[1] Public Utility Finance & Accounting, A Reader (Modified)

[2] Depreciation Systems, by Dr. Frank K. Wolf and Dr. W. C. Fitch, Iowa State Press, 1994, p. 289.

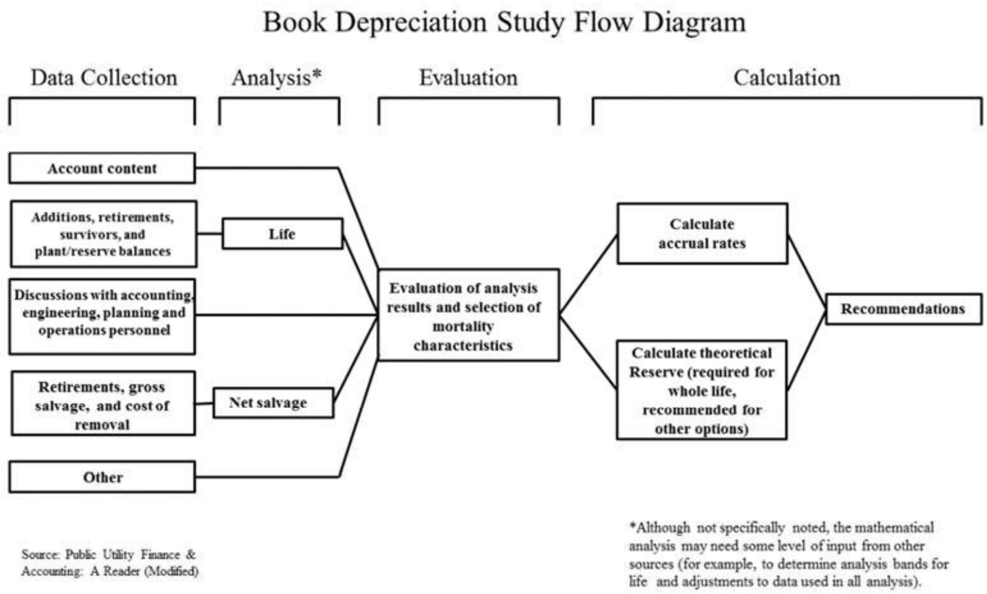


Figure 1

WTG DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation

Annual depreciation expense amounts for the depreciable property accounts of West Texas Gas were calculated by the straight-line, equal-life group, remaining-life system. With this approach, remaining lives were calculated according to standard ELG group expectancy techniques, using the Iowa Survivor Curves noted in the calculation. For each plant account, the difference between the surviving investment, adjusted for estimated net salvage and the allocated book depreciation reserve, was divided by the average remaining life to yield the annual depreciation expense. These calculations are shown in Appendix A.

Remaining Life Calculation

The establishment of appropriate average service lives and retirement dispersions for each account within a functional group was based on engineering judgment that incorporated available accounting information analyzed using the actuarial life analysis, taking into account that many of the assets were acquired and recorded in the fixed asset records with the vintage being the acquisition year. This accounting approach has the effect of requiring shorter depreciable lives than would normally be expected for some asset groups since an asset at “age 0” may already be 30 years old or more. After establishment of appropriate average service lives and retirement dispersion, remaining life was computed for each account. The theoretical depreciation reserve with zero net salvage (used in calculating remaining life) was calculated using theoretical reserve ratios as defined in the theoretical reserve portion of the general discussion section. The difference between plant balance and theoretical reserve was then spread over the ELG depreciation accruals. After accumulating the ELG accruals across each vintage, the annual accrual was divided into the net balance to compute remaining life. Details of the theoretical reserve computations, ELG accruals, and remaining life are found by account within each function in the study workpapers.

LIFE ANALYSIS

The retirement rate, actuarial analysis method was applied to all accounts. Vintage balances and historical transactional data were combined for the Texas and Oklahoma assets operated by the Company for life analysis. For each account where sufficient retirement data exists, an actuarial analysis was made with placement and experience bands of varying width. The historical observed life table was plotted and compared with various Iowa Curves to obtain the most appropriate match. The selected life and curve, by account, is shown in Appendix C. The remainder of placement and experience band analyses is contained in the workpapers.

For each account on the overall band (i.e., placement from earliest vintage year through 2023) and experience band from earliest available experience year (1998) through 2023, the most recently approved survivor curves were used as a starting point. Then, using the same average life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (e.g., L, S, or R) as an obviously better match than others. The next step is to determine the most appropriate life using that dispersion pattern. Generally, the goal of visual matching is to minimize the differential between the observed life table and Iowa Curve in top and mid-range of the plots.

Actuarial analysis was available from 1998-2023. No history was available prior to that period, so the historic life analysis was limited for the longest-lived accounts. With limited retirement history, interviews provided great insight into the Company's operations and the impact that those operations are expected to have on the service lives of the assets used to provide utility service. The acquisition of assets a portion of the way through their lives and the recording of the vintages of those assets as the year of acquisition affect the life of the asset groups. In other words, assets acquired that are 30 years old will appear to be new in the Company's accounting system. As such a 75-year total life for the assets will only carry a 45-year life for depreciation purposes. This information in conjunction with all other factors is used to select the most appropriate life and curve for each asset group.

Intangible Plant Account 303

Account 303 Intangible Plant (15 SQ)

This account includes the cost of intangible assets such as software. There is approximately $378 thousand of current investment in this account. The current life for this account is 17 years with a SQ dispersion. The current investment is fully depreciated and consists primarily of billing software. There has been very limited retirement activity since the prior study. Operational subject matter experts estimate new software assets, such as ERP systems to have an operational life of 15 years. Given the age of the existing assets, mix of assets in this account, and the estimated life of future software assets, this study recommends decreasing to a 15-year life and SQ dispersion for this account.

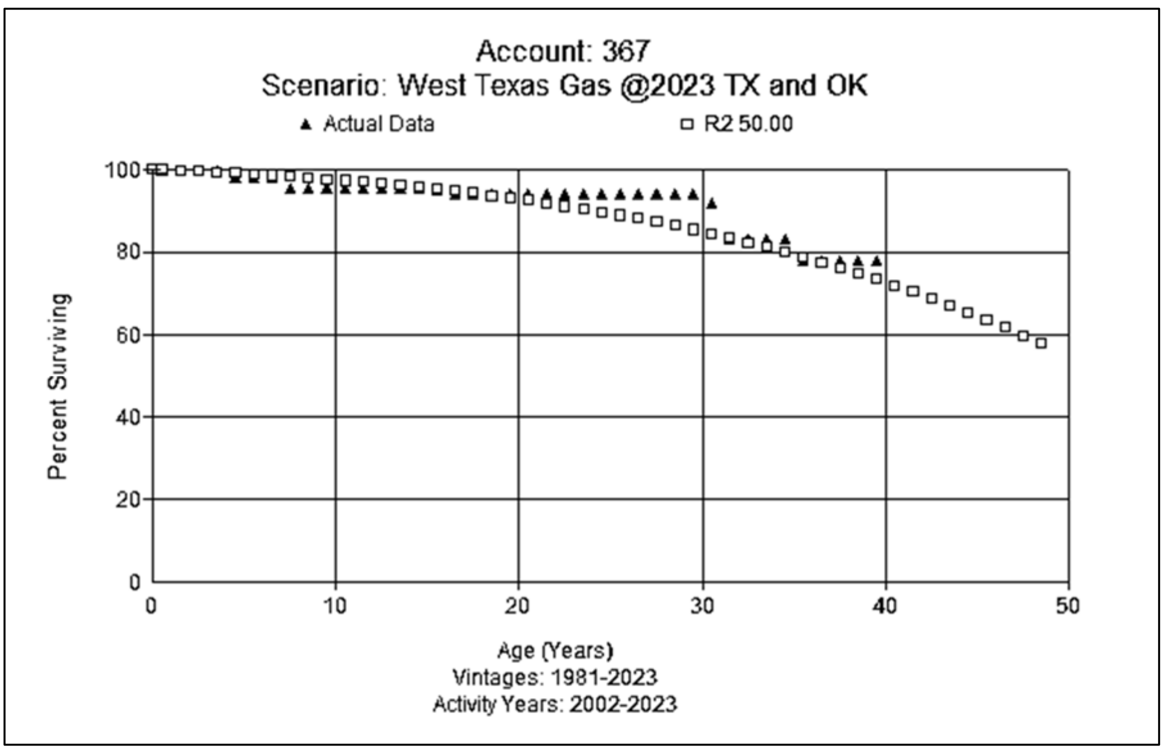
Transmission Plant Accounts 365.2 - 371

Account 365.2 Land Rights (45 SQ)

This account includes the cost of land rights used in the transmission system. There is approximately $5.4 million of current investment in this account. The current life for this account is 45 years with a SQ dispersion. Insufficient data exists to perform a life analysis on this account. Based on the proposed life for Account 367 Transmission Mains and the fact that acquisitions were recorded on the Company's books with a vintage of the year of acquisition, this study recommends retaining the existing 45-year life and SQ dispersion curve for this account.

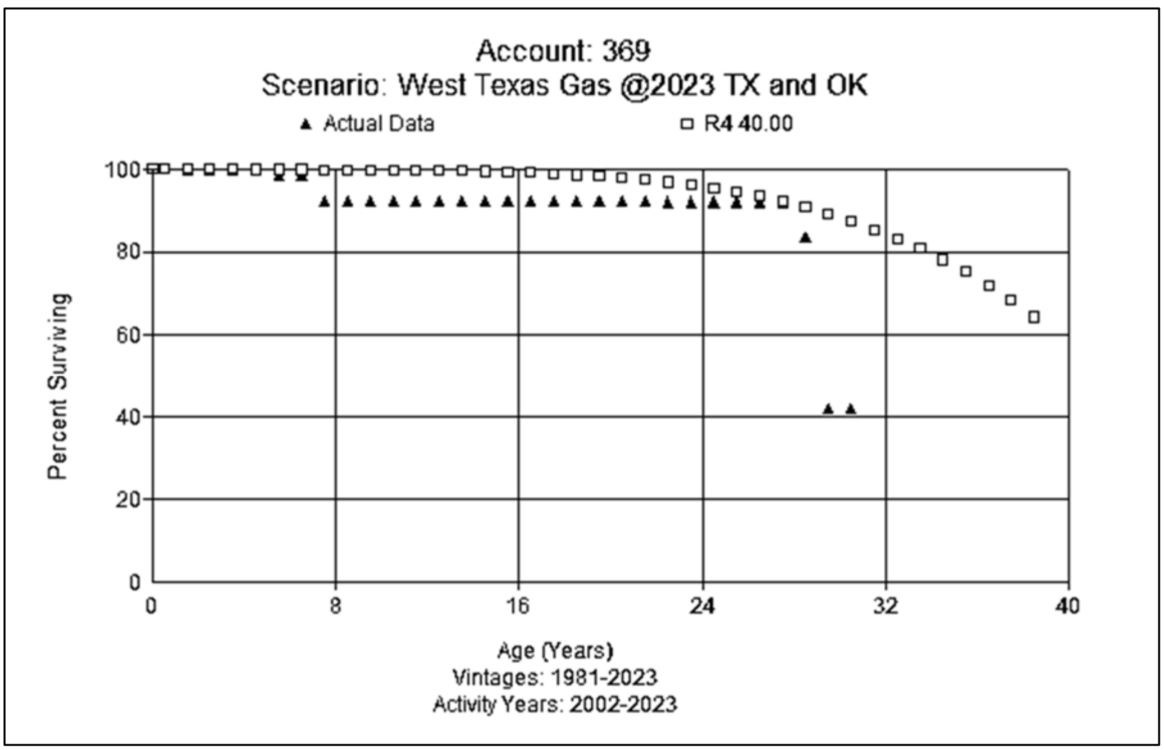
Account 367 Transmission Mains (50 R2)

This account includes transmission mains and related assets. There is approximately $45.3 million of current investment in this account. The current life for this account is 45 years with an R2 dispersion. WTG's assets have been acquired from a variety of sources. When an asset has been acquired it is booked with the vintage as acquisition date rather than the true age of the asset. This impacts the depreciable life of WTG's assets. The average age of current investment in this account, using the acquisition year as the vintage, is 11.9 years. Operational per foot data provided by the Company shows the average physical age of existing steel mains is approximately 48 years. Nearly all of the existing transmission mains are steel. The Company recently replaced approximately 40 miles of the Dalhart system in 2014. Operational personnel estimate the mains being replaced were originally installed in the 1940's and 1950's, making them more than 70 years old at the time of replacement. The new protected steel mains being installed are estimated to have an operational life of 80 years. Based on life analysis, judgment and the fact that acquisitions were recorded on the Company's books with a vintage of the year of acquisition, this study recommends increasing to a 50-year life and an R2 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.



Account 369 Measuring and Regulating Equipment (40 R4)

This account includes transmission measuring and regulating station equipment. There is approximately $1.1 million of current investment in this account. The current life for this account is 40 years with an R4 dispersion. The Company has rebuilt several stations over the last five years and more than half of the current investment relates to newly installed equipment. Control valves, analyzers, and technical analytical equipment, which have a shorter useful life, have been replaced and recorded as Operations and Maintenance expense. Operational subject matter experts anticipate the operational life of the newly installed transmission M&R equipment to be longer than the existing distribution M&R equipment. Based on life analysis, judgment, and the fact that acquisitions were recorded on the Company's books with a vintage of the year of acquisition, this study recommends retaining the existing 40-year life and R4 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.

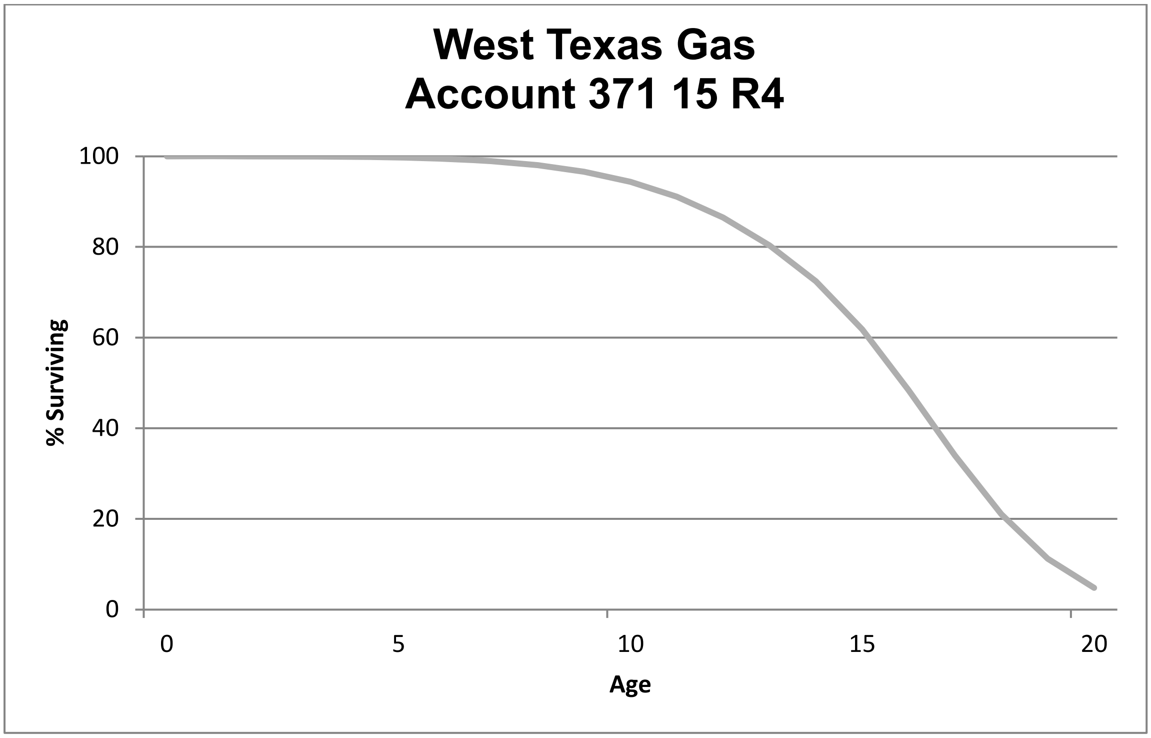


Account 369.1 Transmission Meters (40 R4)

This subaccount includes transmission meters. There is approximately $362 thousand of current investment in this account. The current life for this account is 40 years with an R4 dispersion. Insufficient data exists to perform a life analysis on this account. The Company has meters at both the town border stations and on customer premises. The existing meters were purchased new, as opposed to other assets in the Company being acquired. WTG is currently replacing meters at between 15 and 20 years. At the time of replacement, the meter is tested, rebuilt or recalibrated, and then reinstalled. No retirement is currently being recorded in fixed assets at the time of the refurbishment. Essentially, the meter is going through two life-cycles being rebuilt and reinstalled before it is retired. Based on the existing lifecycle of the meters, information from Company personnel, and judgement, this study recommends retaining the existing 40-year life and R4 dispersion for this account.

Account 371 Other Equipment (15 R4)

This account includes miscellaneous equipment used in transmission operations not booked in the other transmission accounts. There is approximately $224 thousand of current investment in this account. The current life for this account is 20 years with an R5 dispersion. Assets in this account include handheld meter equipment, cathodic protection equipment, Itron accessories, and radios. The small electronic equipment in this account has a relatively short life due to changes in technology. Based on life analysis, the mix of assets in this account, and judgment, this study recommends decreasing to a 15-year life and an R4 dispersion curve for this account. A graph of the proposed dispersion curve is shown below.



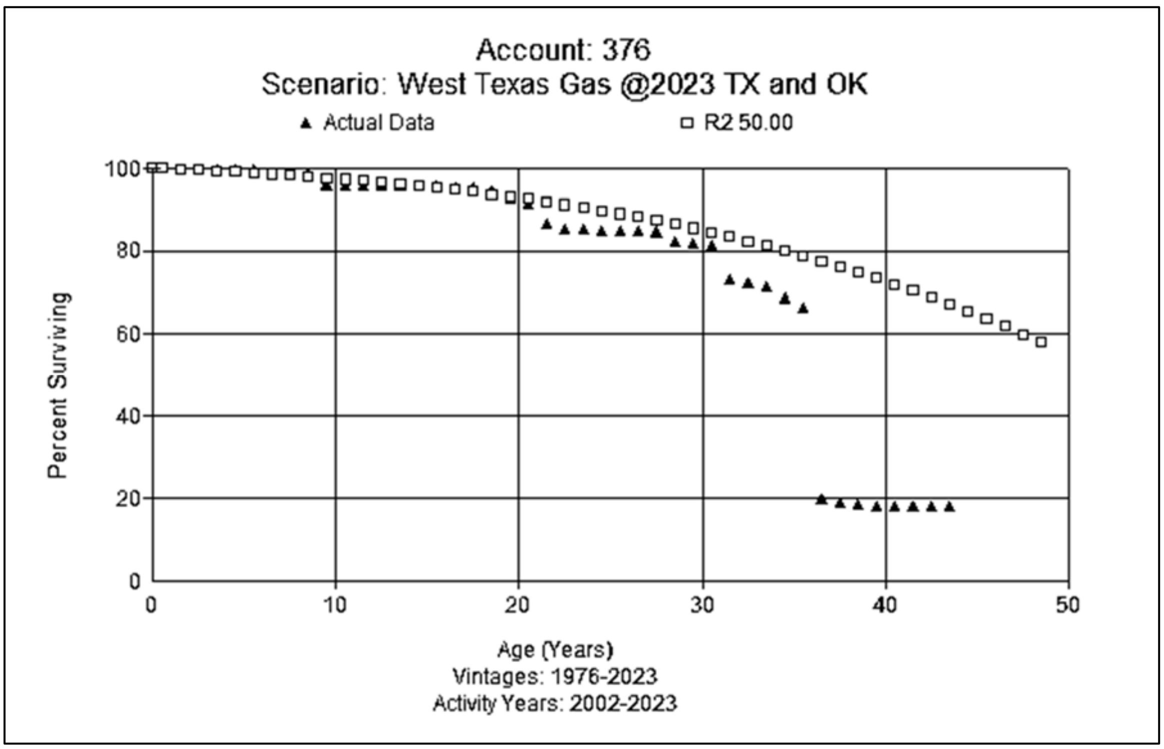
<u>Distribution Plant Accounts 376 - 387</u>

Account 376 Mains (50 R2)

This account includes distribution mains and related assets including services, riser bars, meters, and the meter loop. There is approximately $167.9 million of current investment in this account. The current life for this account is 45 years with an R2 dispersion. The Company operates both plastic and steel distribution mains. WTG's assets have been acquired from a variety of sources. When an asset has been acquired it is booked with the vintage as the acquisition date rather than the original installation date of the asset. This impacts the depreciable life of WTG's assets. The average age of current investment, using the acquisition date to assign a vintage, is 10.03 years. Operational per foot data provided by the Company shows the average physical age of existing steel mains is 52 years and plastic mains is approximately 45 years.

WTG implemented a Distribution Integrity Management Program (DIMP) in

2012 to replace 340 thousand feet of suspect pipe over the next 20 years. Operational subject matter experts estimate the age of the mains being replaced for DIMP is approximately 60 years old. Actuarial analysis shows the existing 45-year life is a better fit. However, more than half of the current investment consists of new main replacements installed since 2013. As the Company continues to add new investment in this account, the average service life is expected to gradually increase over time. Based on life analysis, judgement, and the fact that acquisitions were recorded on the Company's books with a vintage of the year of acquisition, this study recommends increasing to a 50-year life and an R2 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.

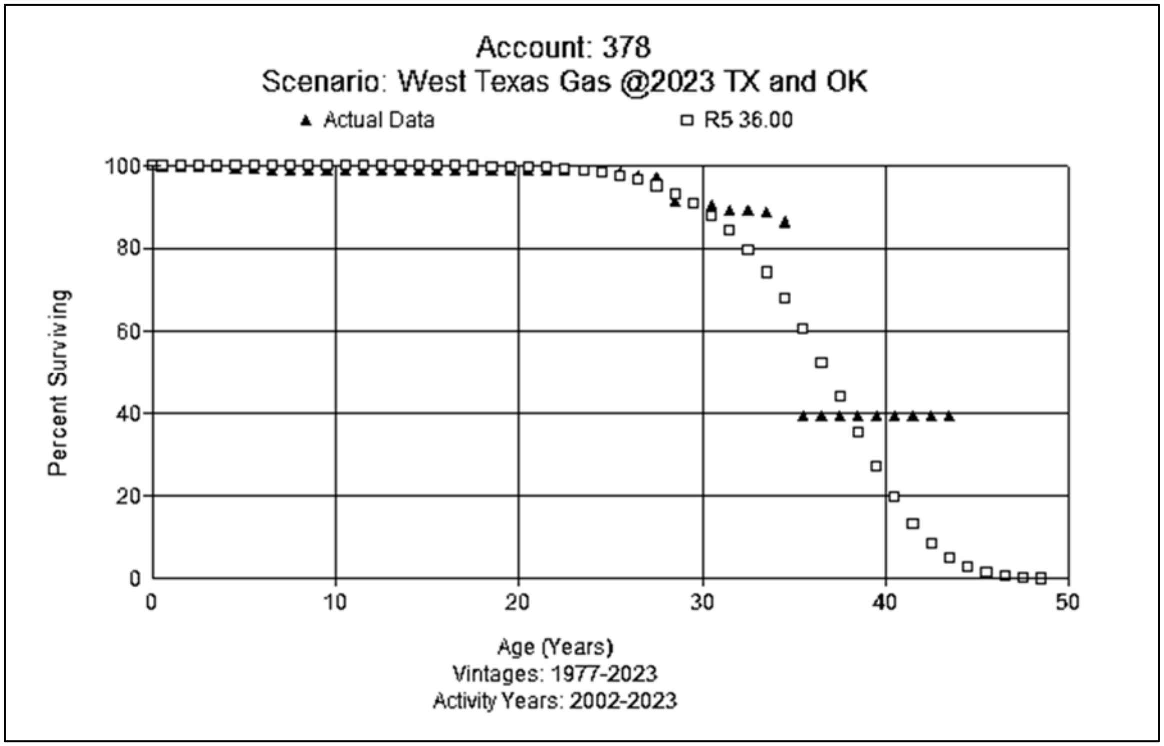


<u>Subaccounts Created for Account 378 Measuring and Regulating Station Equipment</u>

The average service lives of the assets within this account are distinctly different for Measuring and Regulating Station Equipment versus the Meters. WTG is currently using a 36-year life for all assets in Account 378. The Company has decided to create a new subaccount for future investment relating to meters to record these assets with distinct service lives separately. The timing of this filing and limited resources did not allow the Company to split current investment. Therefore, this study factors in information provided by Company subject matter experts and analyzes the limited historical retirement activity for the current mix of assets within Account 378 – M & R Station Equipment and proposes to create Account 378.1 – Meters to record future investment.

Account 378 Measuring and Regulating Station Equipment (36 R5)

This account consists of meters, gauges, and other equipment used in measuring and regulating gas in connection with distribution system operations other than the measurement of gas deliveries to customers. There is approximately $7.7 million of current investment in this account. The current life for this account is 36 years with an R5 dispersion. WTG currently operates both district regulating and city gate stations. Company subject matter experts estimate the town border station equipment has an operational life between 40 and 50 years. Nearly half of the existing investment relates to meters, and the Company is currently experiencing a shorter life for the meters than other measuring and regulating equipment. Based on life analysis, the mix of assets in this account, and judgment, this study recommends retaining the existing 36-year life and R5 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.

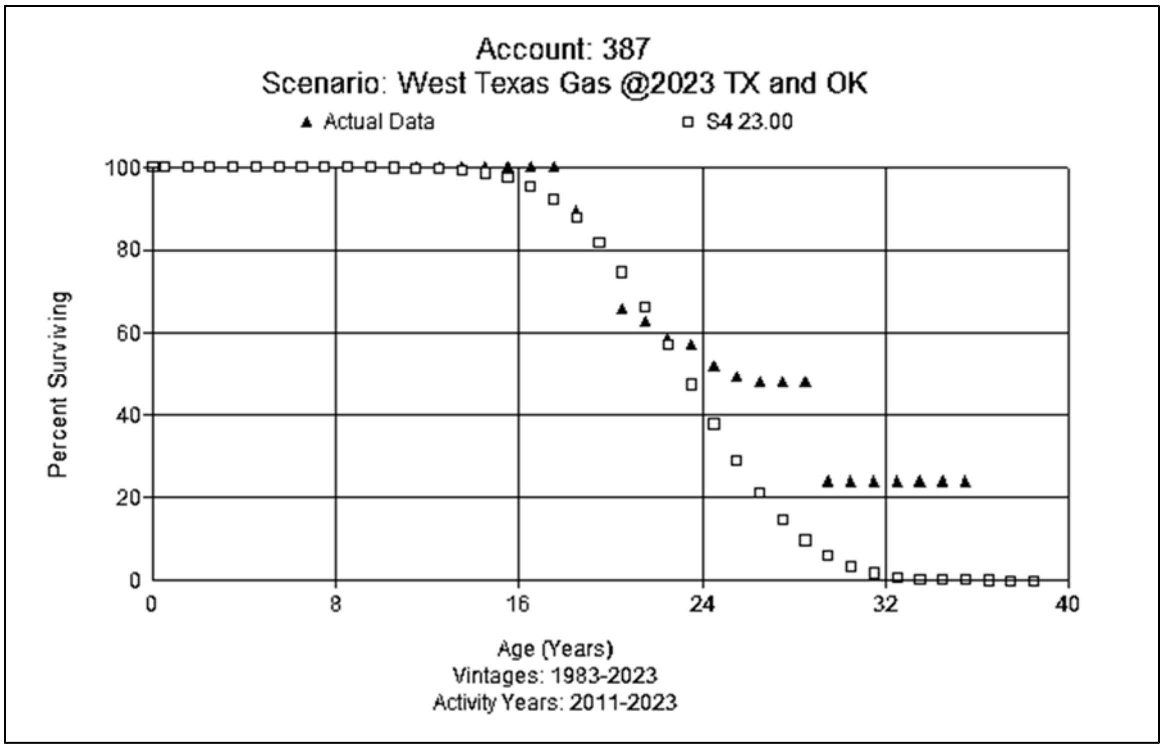


Account 378.1 Meters (20 R2)

This new subaccount is being created to track future investment related to meters separately from other regulating station equipment. Meters have a shorter operating life than other M & R station equipment. Company subject matter experts estimate the meters have an operational life around 20 years. Approximately 10 percent of the current meters are ERTS. The Company is starting to experience more battery failures on meters installed in 2010. The battery replacements are currently being expensed. experiencing a shorter life for Based on meters having a shorter life than other measuring and regulating equipment, this study recommends using a 20-year life and R5 dispersion curve for future investment in this new subaccount.

Account 387 Other Equipment (23 S4)

This account includes the cost of other equipment including Itron meter reading equipment, a tapping machine, leak detectors, and other related equipment used for distribution operations. There is approximately $688 thousand of current investment in this account. The current life for this account is 23 years with an S4 dispersion. The Company is currently experiencing a 10-year operating life for meter readers. Rectifiers are being replaced around 40 years and the electronic temperature correctors are operational for about 20 years. The tapping machine is estimated to have a useful life of at least 30 years. Based on life analysis, the mix of assets in this account, and judgment, this study recommends retaining the existing 23-year life and an S4 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.



General Plant Accounts 389 - 398

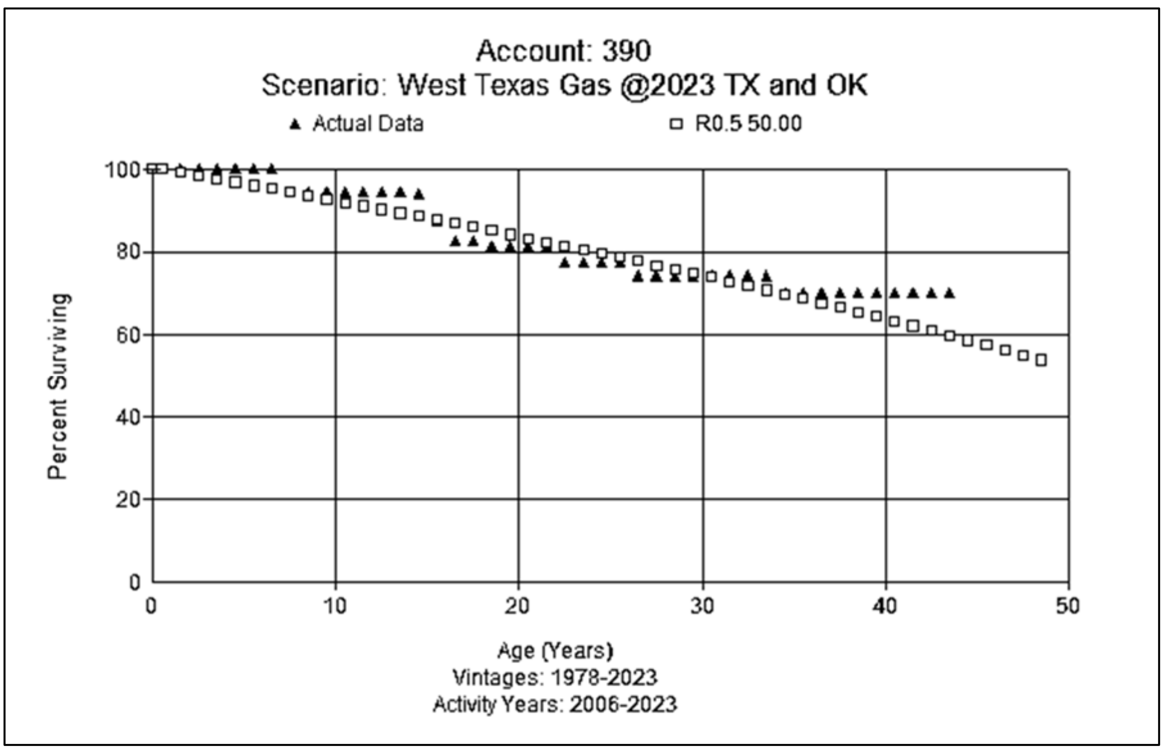
General Plant Depreciated Accounts

Account 389 Land Rights (50 SQ)

This account includes the cost of land rights associated with general plant facilities. There is approximately $6.3 million of current investment in this account. The current life for this account is 45 years with an SQ dispersion. There is insufficient data to analyze this account. Based on the proposed life for Account 390 Structures and Improvements and the fact that acquisitions were recorded on the Company's books with a vintage of the year of acquisition, this study recommends increasing to a 50-year life and SQ dispersion curve for this account.

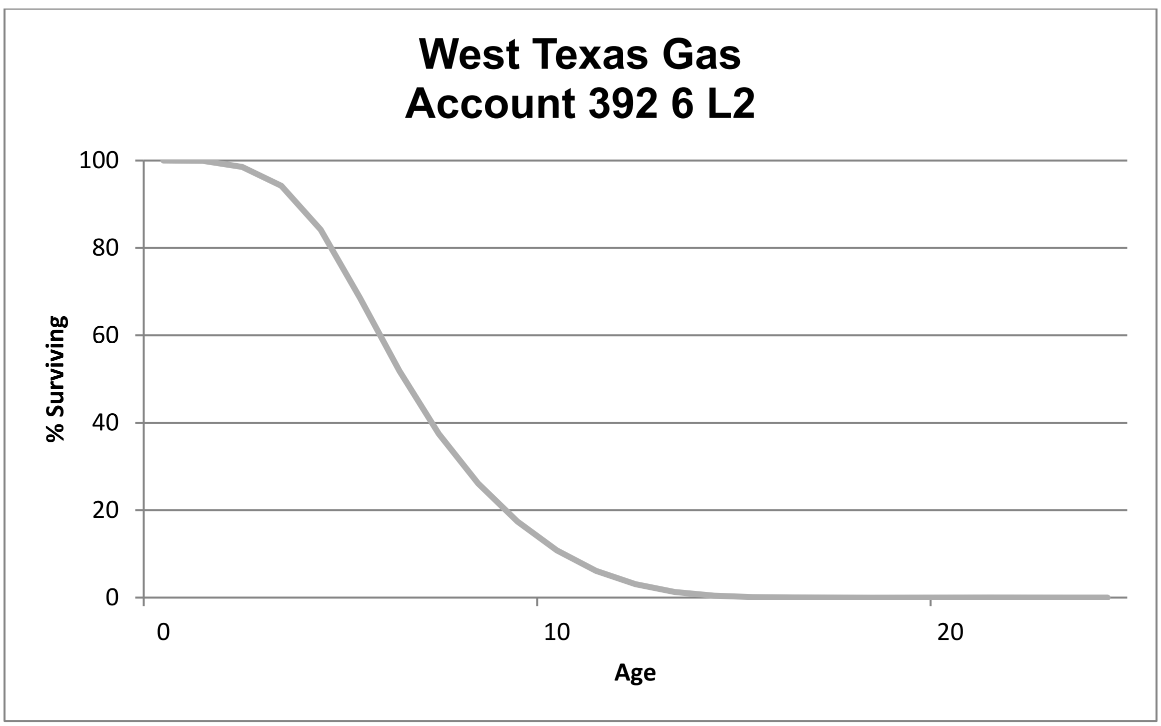
Account 390 Structures & Improvements (50 R0.5)

This account includes the cost of structures and improvements used for utility service. There is approximately $4.6 million of current investment in this account. The current life for this account is 45 years with an R0.5 dispersion. Nearly half of the existing investment relates to the new Amarillo office built in 2019. Based on life analysis, the mix of assets in the account and judgment, this study recommends increasing to a 50-year life and R0.5 dispersion curve for this account. A graph of the proposed curve versus actual data is shown below.



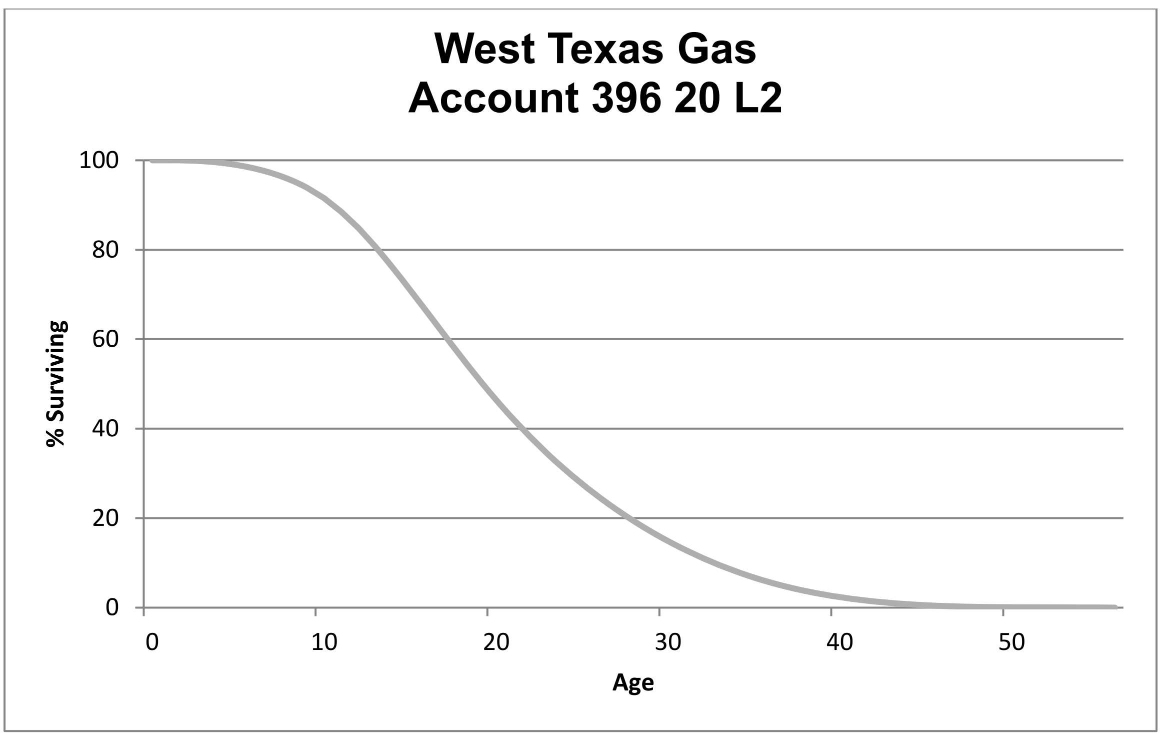
Account 392 Transportation Equipment (6 L2)

This account consists of motor cars, trucks, and other transportation equipment that can be licensed on roadways. There is approximately $2.9 million of current investment in this account. The current life for this account is 8 years with an L2 dispersion. The majority of existing investment relates to pickup trucks. The Company currently replaces vehicles based on mileage approximately every 6 years. Operations has been experiencing a shorter life for many of the vehicles due to transmission failures and retiring vehicles earlier. While reviewing the operating lives of the various assets in this account, investment related to the longer-lived assets, such as backhoes and excavators, previously recorded in this account has been transferred to Account 396 Power Operating Equipment. Based on life analysis, the current mix of assets in this account, and judgment, this study recommends decreasing to a 6-year life and retaining the existing L2 dispersion curve for this account. A graph of the proposed dispersion curve is shown below.



Account 396 Power Operating Equipment (20 L2)

This newly created account consists of operating equipment such as excavators, backhoes, forklifts, and other power operating equipment used to support gas operations. Approximately $356 thousand of current investment was transferred from other general plant accounts. This account was newly created to track power operating equipment, which typically has a longer operating life separately from licensed transportation equipment recorded in Account 392. Most of the existing investment relates to excavators, which have an estimated operating life of 20 years depending on usage and number of operating hours. Based on the mix of assets in this account and judgment, this study recommends using a 20-year life and an L2 dispersion curve for this account. A graph of the proposed dispersion curve is shown below.



General Plant Amortized Accounts

This study continues the use of vintage group amortization for select amortized general plant accounts, following Accounting Release 15 guidelines, which is the same methodology approved in the Company's previous depreciation study. When using this methodology, assets whose age is longer than the recommended service life for each group are retired. Those amounts are shown for each account in Appendix A. After those assets are retired, the remaining plant in service for each account will be amortized using the amortization rates shown in Appendices A and B. Annually, assets which reach the average service life of each account are retired when the assets reach their average service life.

Account 391 Office Furniture and Equipment (20 SQ)

This account consists of miscellaneous office furniture such as desks, chairs, filing cabinets, and tables. There is approximately $266 thousand of current investment after retirement of fully accrued assets. The current life for this account is 20 years with a SQ dispersion. Actuarial analysis indicates a slightly shorter life; however, existing investment includes copiers and scanning equipment that are currently 10 years old and expected to last another 5 or 10 years. The Company recently added an imaging system in 2013 that includes software and scanners, which they expect to last at least 20 years. Based on judgment and the types of assets in the account, this study recommends retaining the existing 20-year life and a SQ dispersion curve for this account.

Account 391.1 Computer Equipment (5 SQ)

This account consists of laptops, monitors, and other related computer equipment. There is approximately $8 thousand of current investment after retirement of fully accrued assets. The current life for this account is 5 years with a SQ dispersion. The Company typically replaces computers and related equipment using a 5-year lifecycle. Based on life analysis and judgment, this study recommends retaining the existing 5-year life and SQ dispersion curve for this account.

Account 394 Tools, Shop, and Garage Equipment (25 SQ)

This account consists of various items or tools used in shops and garages, including meter reading equipment, leak detectors, and other related field equipment. There is approximately $1.2 million of current investment in this account. The current life for this account is 25 years with a SQ dispersion. Existing investment includes an odorization system, air compressors, and a welder, which have at least a 20-year life. Leak detectors are also estimated to have an operational life of 20 years. The tapping machine is estimated to have a useful life of at least 30 years. Operations stated the lives and type of assets in this account are similar to the assets in Account 387 Other Equipment, which is using a 23-year life. Based on life analysis, information provided by Company personnel, and judgment, this study recommends retaining the existing 25-year life and a SQ dispersion curve for this account.

Account 397 Communication Equipment (12 SQ)

This account consists of miscellaneous communication equipment, such as microwave equipment, radio equipment, and SCADA equipment. There is approximately $529 thousand of current investment after retirement of fully accrued assets. The current life for this account is 15 years with an SQ dispersion. The majority of investment relates to a SCADA system installed in 2017, which included capitalized software and related electronic equipment estimated to have an operational life between 10 and 12 years. The Company is currently experiencing a shorter life between 10 and 12 years for radios due to fast changing technology. Based on life analysis, the current mix of assets, and judgment, this study recommends decreasing to a 12-year life and retaining the existing SQ dispersion curve for this account.

Account 398 Miscellaneous Equipment (15 SQ)

This account consists of miscellaneous equipment such as steel storage containers, tools, ice machines, and security equipment. This account contains $160 thousand of current investment after retirement of fully accrued assets. The steel containers are approximately 5 years old and are expected to last at least 15 years. Based on life analysis and judgment, this study recommends retaining the existing 15-year life and a SQ dispersion curve for this account.

NET SALVAGE ANALYSIS

When a capital asset is retired, physically removed from service and finally disposed of, terminal retirement is said to have occurred. The residual value of a terminal retirement is called gross salvage. Net salvage is the difference between the gross salvage (what the asset was sold for) and the removal cost (cost to remove and dispose of the asset). Gross salvage and removal cost percentages are calculated by dividing the current cost of salvage or removal by the original installed cost of the asset. Historically, WTG has booked removal costs to the cost of a new installation. Consistent with the general practice for other regulated natural gas utilities, Alliance Consulting Group recommends that the Company move to tracking gross salvage and removal. The current study assumes a zero percent net salvage in depreciation rates, with the exception of vehicles.

WTG has consistently recorded gross salvage at the time of retirement for vehicles since 2012. Alliance analyzed combined gross salvage from its Texas and Oklahoma operations for Account 392 Transportation Equipment. Historical transactional data was available from 2012 to 2023. The net salvage data is discussed below for this account. A detailed calculation of rolling net salvage percentages for Account 392 is provided in Appendix D.

Account 392 Transportation Equipment (10 Percent)

This account includes any salvage related to transportation equipment such as licensed cars and trucks. There is currently positive 10 percent net salvage for this account. No removal cost has been recorded in this account. Current analysis indicates an increasing positive net salvage percentage since 2012. The 10-year rolling net salvage percent has ranged from positive 4.30 percent to 12.08 percent. Based on net salvage analysis, consistent amounts of positive salvage being recorded, and judgement, this study recommends retaining the existing positive 10 percent net salvage for this account.

Account 396 Operating Equipment (10 Percent)

This is a new account being added since the last study. This account will include salvage related to power operating equipment. The current assets in this account were transferred from Account 392 Transportation Equipment and other general plant accounts. Typically, when retiring power operating equipment, there is minimal removal cost and salvage is recorded, similar to equipment in Account 392. Based on the net salvage experience for similar assets in Account 392 and judgement, this study recommends a positive 10 percent net salvage for this account.

APPENDIX A
Computation of Annual Accrual Rates and Amounts

WEST TEXAS GAS
Computation of Proposed Depreciation Accrual Rates and Amounts - Texas
Using Equal Life Group Depreciation
As of December 31, 2023

Account	Description	Plant Balance at 12/31/2023	Allocated Book Reserve	Net Salvage %	Net Salvage Amount	Unaccrued Balance	Average Remaining Life	Annual Accrual Amount	Annual Accrual Rate	
(a)	(b)	(c)	(d)	(e)	(f)= (e)/100*(c)	(g)=(c)-(d)-(f)	(h)	(i)=(g)/(h)	(j)=(i)/(c)	
Intantible Plant										
303	Intangible Plant	378,314.96	626,340.11	0%	-	(248,025.15)	0.00	-	0.00%	Note 1
	Total Intangible Plant	378,314.96	626,340.11		-	(248,025.15)				
Gathering Plant										
332	Field Lines	3,048,810.58	3,345,891.64	0%	-	(297,081.06)	16.62	-	0.00%	Note 1
334	Field Measuring & Regulating Equip	100,000.00	100,000.00	0%	-	-	9.82	-	0.00%	Note 1
	Total Gathering Plant	3,148,810.58	3,445,891.64		-	(297,081.06)		-		
Transmission Plant										
365.2	Land Rights	5,379,123.47	1,270,864.57	0%	-	4,108,258.90	35.36	116,171.08	2.16%	
367	Transmission Mains	45,312,826.71	13,084,107.96	0%	-	32,228,718.75	32.05	1,005,481.75	2.22%	
369	Field Measuring and Regulating Eqiupment	1,051,356.12	375,755.55	0%	-	675,600.57	25.87	26,114.26	2.48%	
369.1	Meters and Regulators	362,104.33	152,761.73	0%	-	209,342.60	23.77	8,805.41	2.43%	
371	Other Eqiupment	224,147.69	196,806.23	0%	-	27,341.46	3.18	8,585.22	3.83%	
	Total Transmission Plant	52,329,558.32	15,080,296.03		-	37,249,262.29		1,165,157.73		
Distribution Plant										
376	Distribution Mains	167,901,504.47	42,000,100.42	0%	-	125,901,404.05	32.56	3,866,867.35	2.30%	
378	Distribution Measuring and Regulating Eqiup	7,698,513.86	4,191,400.66	0%	-	3,507,113.20	18.89	185,707.82	2.41%	
378.1	Meters	-							5.00%	Note 2
387	Other Eqiupment	688,098.21	513,486.62	0%	-	174,611.59	8.11	21,527.86	3.13%	
	Total Distribution Plant	176,288,116.54	46,704,987.70		-	129,583,128.84		4,074,103.03		
General Plant - Depreciated										
389	General Plant Land Rights	6,308,628.50	2,473,585.09	0%	-	3,835,043.41	33.43	114,717.55	1.82%	
390	Structures and Improvements	4,562,845.55	1,045,660.50	0%	-	3,517,185.05	28.28	124,373.07	2.73%	
392	Transportation Equipment	2,912,606.36	1,828,299.18	10%	291,260.64	793,046.55	2.60	304,654.70	10.46%	
396	Power Operating Equipment	356,491.76	150,821.70	10%	35,649.18	170,020.89	11.09	15,334.24	4.30%	
		14,140,572.17	5,498,366.46		326,909.81	8,315,295.90		559,079.56		

General Plant - Amortized

Account	Description	Plant Balance at 12/31/2019	Allocated Book Reserve	Theoretical Reserve	Reserve Deficit	Remaining Life	Amortized Reserve Difference	Asset to Retire
391	Office Furniture and Euqipment	326,694.56	180,893.66	162,281.90	18,611.75	10.07	1,849.12	60,673.37
391.1	Computer Equipment	96,090.77	94,450.97	93,786.19	664.78	1.51	439.34	88,475.55
394	Tools, Shop, and Garage Equipment	1,290,075.98	725,056.13	641,071.10	83,985.03	12.58	6,677.74	76,304.15
397	Communication Equipment	583,844.64	357,357.37	311,216.47	46,140.90	5.60	8,234.39	54,358.23
398	Miscellaneous Equipment	250,526.44	140,026.75	132,301.58	7,725.17	7.08	1,091.34	90,127.00
		2,547,232.39	1,497,784.88	1,340,657.25	157,127.63		18,291.92	369,938.30

After Retirement of Fully Accrued Assets

Account	Description	Plant Balance at 12/31/2019	Allocated Book Reserve	Proposed Life	Accrual Rate	Annual Amortization	Accrual for Reserve Difference
391	Office Furniture and Euqipment	266,021.19	120,220.29	20.00	5.00%	13,301.06	(1,849.12)
391.1	Computer Equipment	7,615.22	5,975.42	5.00	20.00%	1,523.04	(439.34)
394	Tools, Shop, and Garage Equipment	1,213,771.83	648,751.98	25.00	4.00%	48,550.87	(6,677.74)
397	Communication Equipment	529,486.41	302,999.14	12.00	8.33%	44,123.87	(8,234.39)
398	Miscellaneous Equipment	160,399.44	49,899.75	15.00	6.67%	10,693.30	(1,091.34)
		2,177,294.09	1,127,846.58			118,192.14	(18,291.92)

Note 1 Existing investment is fully depreciated. Company should apply a Whole Life rate as follows for new investment:
Account 303 6.67% (1/15)
Account 332 2.22% (1/45)
Account 334 2.78% (1/36)

Note 2 New Subaccount 378.1 Distribution Meters should apply Whole Life rate of 5.00% (1/20) for new investment in Meters

APPENDIX A-1
Computation of Remaining Life

Appendix A-1

WEST TEXAS GAS
Computation of Remaining Life - Texas
Using Equal Life Group Depreciation
As of December 31, 2023

Account	Description	Plant Balance at 12/31/2023	Theoretical Reserve 0%	Undepreciated Balance	Annual Accrual	Remaining Life
	(a)	(b)	(c)	(d)= (b) - (c)	(e)	(f)=(d)/(e)
303	Intangible Plant	378,314.96	378,314.96	-	18,137.38	0.00
332	Field Lines	3,048,810.58	1,963,423.68	1,085,386.90	65,297.99	16.62
334	Field Measuring & Regulating Equip	100,000.00	73,681.20	26,318.80	2,679.32	9.82
365.2	Land Rights	5,379,123.47	1,151,865.38	4,227,258.09	119,536.08	35.36
367	Transmission Mains	45,312,826.71	11,858,959.07	33,453,867.64	1,043,704.33	32.05
369	Measuring and Regulating Equipment	1,051,356.12	340,571.15	710,784.97	27,474.25	25.87
369.1	Meters and Regulators	362,104.33	138,457.67	223,646.66	9,407.07	23.77
371	Other Eqiupment	224,147.69	182,980.43	41,167.26	12,926.53	3.18
376	Distribution Mains	167,901,504.47	36,487,340.70	131,414,163.77	4,036,183.26	32.56
378	Distribution Measuring and Regulating Equipment	7,698,513.86	3,658,778.44	4,039,735.42	213,911.10	18.89
387	Other Eqiupment	688,098.21	463,879.92	224,218.29	27,643.87	8.11
389	General Plant Land Rights	6,308,628.50	2,090,640.07	4,217,988.43	126,172.57	33.43
390	Structures and Improvements	4,562,845.55	883,777.86	3,679,067.69	130,097.49	28.28
392	Transportation Equipment	2,912,606.36	1,718,483.18	1,194,123.18	458,731.26	2.60
396	Power Operating Equipment	356,491.76	141,636.03	214,855.73	19,377.91	11.09

APPENDIX B

Comparison of Existing versus Proposed Accrual Rates and Amounts

WEST TEXAS GAS
Comparison of Existing versus Proposed Accrual Rates and Amounts - Texas
As of December 31, 2023

			Existing Annual Accrual		Proposed Annual Accrual			
Account	**Description**	**Plant Balance at 12/31/2023**	**Rate %**	**Amount**	**Rate %**	**Amount**	**Difference**	
(a)	**(b)**	**(c)**	**(d)**	**(e)=(c)*(d)**	**(f)**	**(g)=(c)*(f)**	**(h) = (g) - (e)**	
Intantible Plant								
303	Intangible Plant	378,314.96	0.00%	-	0.00%	-	-	Note 1
	Total Intangible Plant	378,314.96		-		-	-	
Gathering Plant								
332	Field Lines	3,048,810.58	0.00%	-	0.00%	-	-	Note 1
334	Field Measuring & Regulating Equip	100,000.00	0.00%	-	0.00%	-	-	Note 1
	Total Gathering Plant	3,148,810.58		-		-	-	
Transmission Plant								
365.2	Land Rights	5,379,123.47	2.21%	118,878.63	2.16%	116,171.08	(2,707.55)	
367	Transmission Mains	45,312,826.71	2.54%	1,150,945.80	2.22%	1,005,481.75	(145,464.05)	
369	Field Measuring and Regulating Eiqupment	1,051,356.12	2.61%	27,440.39	2.48%	26,114.26	(1,326.14)	
369.1	Meters and Regulators	362,104.33	2.54%	9,197.45	2.43%	8,805.41	(392.04)	
371	Other Eiqupment	224,147.69	4.85%	10,871.16	3.83%	8,585.22	(2,285.94)	
	Total Transmission Plant	52,329,558.32		1,317,333.43		1,165,157.73	(152,175.71)	
Distribution Plant								
376	Distribution Mains	167,901,504.47	2.61%	4,382,229.27	2.30%	3,866,867.35	(515,361.92)	
378	Distribution Measuring and Regulating Eqiup	7,698,513.86	2.61%	200,931.21	2.41%	185,707.82	(15,223.39)	
378.1	Meters	-			5.00%	-		Note 2
387	Other Eiqupment	688,098.21	3.81%	26,216.54	3.13%	21,527.86	(4,688.68)	
	Total Distribution Plant	176,288,116.54		4,609,377.02		4,074,103.03	(535,273.99)	
General Plant - Depreciated								
389	General Plant Land Rights	6,308,628.50	2.01%	126,803.43	1.82%	114,717.55	(12,085.89)	
390	Structures and Improvements	4,562,845.55	4.24%	193,464.65	2.73%	124,373.07	(69,091.58)	
392	Transportation Equipment	2,912,606.36	10.66%	310,483.84	10.46%	304,654.70	(5,829.14)	
396	Power Operating Equipment	356,491.76			4.30%	15,334.24	15,334.24	
		14,140,572.17		630,751.92		559,079.56	(71,672.36)	

WEST TEXAS GAS
Comparison of Existing versus Proposed Accrual Rates and Amounts - Texas
As of December 31, 2023

Account	Description	Plant Balance at 12/31/2023	Existing Annual Accrual Rate %	Existing Annual Accrual Amount	Proposed Annual Accrual Rate %	Proposed Annual Accrual Amount	Difference
(a)	(b)	(c)	(d)	(e)=(c)*(d)	(f)	(g)=(c)*(f)	(h) = (g) - (e)
General Plant - Amortized							
391	Office Furniture and Euqipment	266,021.19	5.00%	13,301.06	5.00%	13,301.06	-
391.1	Computer Equipment	7,615.22	20.00%	1,523.04	20.00%	1,523.04	-
394	Tools, Shop, and Garage Equipment	1,213,771.83	4.00%	48,550.87	4.00%	48,550.87	-
397	Communication Equipment	529,486.41	6.67%	35,316.74	8.33%	44,123.87	8,807.12
398	Miscellaneous Equipment	160,399.44	6.67%	10,698.64	6.67%	10,693.30	(5.35)
		2,177,294.09		109,390.36		118,192.14	8,801.78
	Amortized Reserve Difference					(18,291.92)	(18,291.92)
Grand Total		248,462,666.66		6,666,852.74		5,898,240.53	(768,612.21)

Note 1 Existing investment is fully depreciated. Company should apply a Whole Life rate as follows for new investment:
Account 303 6.67% (1/15)
Account 332 2.22% (1/45)
Account 334 2.78% (1/36)

Note 2 New Subaccount 378.1 Distribution Meters should apply Whole Life rate of 5.00% (1/20) for new investment in Meters

APPENDIX C

Comparison of Depreciation Parameters

WEST TEXAS GAS
Comparison of Existing versus Proposed Life Parameters
at December 31, 2023

		Existing			Proposed		
Account		**Life**	**Curve**	**Net Salvage**	**Life**	**Curve**	**Net Salvage**
(a)	(b)						
303	Intangible Plant	17	SQ	0%	15	SQ	0%
332	Field Lines	45	R3	0%	45	R3	0%
334	Field Measuring & Regulating Equip	36	R4	0%	36	R4	0%
365.2	Land Rights	45	SQ	0%	45	SQ	0%
367	Transmission Mains	45	R2	0%	50	R2	0%
369	Measuring and Regulating Equipment	40	R4	0%	40	R4	0%
369.1	Meters and Regulators	40	R4	0%	40	R4	0%
371	Other Eqiupment	20	R5	0%	15	R4	0%
376	Distribution Mains	45	R2	0%	50	R2	0%
378	Distribution Measuring and Regulating Equipment	36	R5	0%	36	R5	0%
378.1	Meters				20	R2	0%
387	Other Eqiupment	23	S4	0%	23	S4	0%
389	General Plant Land Rights	45	SQ	0%	50	SQ	0%
390	Structures and Improvements	45	R0.5	0%	50	R0.5	0%
391	Office Furniture and Equipment	20	SQ	0%	20	SQ	0%
391.1	Computer Equipment	5	SQ	0%	5	SQ	0%
392	Transportation Equipment	8	L2	10%	6	L2	10%
394	Tools, Shop, and Garage Equipment	25	SQ	0%	25	SQ	0%
396	Power Operating Equipment				20	L2	10%
397	Communication Equipment	15	SQ	0%	12	SQ	0%
398	Miscellaneous Equipment	15	SQ	0%	15	SQ	0%

APPENDIX D
Net Salvage Analysis

Appendix D

WEST TEXAS GAS
Net Salvage Analysis
At December 31, 2023

Acct	Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %	2- yr Net Salv. %	3- yr Net Salv. %	4- yr Net Salv. %	5- yr Net Salv. %	6- yr Net Salv. %	7- yr Net Salv. %	8- yr Net Salv. %	9- yr Net Salv. %	10- yr Net Salv. %
Account 392 Automobiles															
392.0	2012	1,987,561	5,850	0	5,850	0.29%									
392.0	2013	49,807	3,500	0	3,500	7.03%	0.46%								
392.0	2014	124,242	12,403	0	12,403	9.98%	9.14%	1.01%							
392.0	2015	412,647	11,850	0	11,850	2.87%	4.52%	4.73%	1.31%						
392.0	2016	418,629	9,200	0	9,200	2.20%	2.53%	3.50%	3.68%	1.43%					
392.0	2017	228,257	7,100	0	7,100	3.11%	2.52%	2.66%	3.43%	3.57%	1.55%				
392.0	2018	146,109	14,500	0	14,500	9.92%	5.77%	3.88%	3.54%	4.14%	4.24%	1.91%			
392.0	2019	288,387	37,390	0	37,390	12.97%	11.94%	8.90%	6.31%	5.36%	5.71%	5.75%	2.78%		
392.0	2020	449,240	36,200	0	36,200	8.06%	9.98%	9.97%	8.56%	6.82%	5.98%	6.22%	6.24%	3.36%	
392.0	2021	486,191	59,356	0	59,356	12.21%	10.22%	10.86%	10.76%	9.67%	8.12%	7.23%	7.36%	7.36%	4.30%
392.0	2022	260,237	21,000	0	21,000	8.07%	10.77%	9.75%	10.37%	10.33%	9.45%	8.11%	7.31%	7.43%	7.42%
392.0	2023	1,148,220	269,694	0	269,694	23.49%	20.64%	18.48%	16.48%	16.09%	15.77%	14.81%	13.27%	12.15%	12.08%

Retirement and Salvage Amounts combine TX and OK

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-24-017	Matanuska Electric Coop	2024	Electric Depreciation Study
New Mexico	Public Service of New Mexico	24-00089-UT	PNM Resources	2024	Electric Technical Update
Texas	Public Utility Commission of Texas	56665	Texas Water Utilities	2024	Water/Wastewater Depreciation Study
Multi-state	FERC	EL24-60-000	Viridon Mid-Atlantic LLC	2024	Electric Transmission Depreciation Study
Multi-state	FERC	EL24-66-000	Viridon Southwest LLC	2024	Electric Transmission Depreciation Study
Multi-state	FERC	EL24-67-000	Viridon New York Inc.	2024	Electric Transmission Depreciation Study
Multi-state	FERC	EL24-69-000	Viridon Midcontinent LLC	2024	Electric Transmission Depreciation Study
North Carolina	North Carolina Utilities Commission	G-9, Sub 837	Piedmont Natural Gas	2024	Gas Depreciation Study
Mississippi	FERC	ER-24-1652-000	Mississippi Power Company	2024	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR24020158	Elizabethtown Gas Company	2024	Gas Depreciation Study
Texas New Mexico	FERC	ER24-1431-000	Southwestern Public Service Company	2024	Electric Technical Update
Missouri	Missouri Public Service Commission	WR-2024-0104	Liberty Utilities Missouri Water	2024	Water Depreciation Study
Missouri	Missouri Public Service Commission	SR-2024-0105	Liberty Utilities Missouri Waste Water	2024	Waste Water Depreciation Study
Texas	Public Utility Commission of Texas	56211	CenterPoint	2024	Electric Depreciation Study
California	California Public Utilities Commission	A.24-01-001	San Jose Water Co	2024	Water/Wastewater Depreciation Study
Missouri	Missouri Public Service Commission	GR-2024-0106	Liberty Utilities Midstates Gas	2024	Gas Depreciation Study
Pennsylvania	Pennsylvania Public Utility Commission	R-2024-3045193	Veolia Pennsylvania	2024	WasteWater Depreciation Study
Pennsylvania	Pennsylvania Public Utility Commission	R-2024-3045192	Veolia Pennsylvania	2024	Water Depreciation Study
Arkansas	Arkansas Public Service Commission	23-079-U	Summit Utilities Arkansas	2024	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	23A-0632G	Atmos Energy	2023	Gas Clean Heat Plan
Oklahoma	Oklahoma Corporation Commission	2023-00087	Oklahoma Gas & Electric	2023	Electric Depreciation Study
Illinois	Illinois Commerce Commission	24-0043	Liberty Mid States Gas- Illinois	2023	Gas Depreciation Study

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Michigan	Michigan Public Service Commission	U-21513	Upper Peninsula Power Company	2023	Electric Depreciation Study
Texas	Public Utility Commission of Texas	55867	Lower Colorado River Authority	2023	Electric Depreciation Study
Texas	Railroad Commission of Texas	Case No. OS-23-00015513	CenterPoint Texas Gas	2023	Gas Depreciation Study
Nevada	Public Utility Commission of Nevada	23-090-12	Southwest Gas	2023	Gas Depreciation Study - Nevada Division
Louisiana	Public Service Commission of Louisiana	36959	Entergy Louisiana	2023	Electric Depreciation Study
Texas	Railroad Commission of Texas	13758	Atmos Energy - APT	2023	Gas Depreciation Study
Florida	Florida Public Service Commission	20230023	People Gas System	2023	Gas Depreciation Study
Texas	Public Utility Commission of Texas	54565	Central States Water Resources (CSWR Texas)	2023	Water Depreciation Study
Louisiana	Louisiana Public Service Commission	U-36923	Cleco	2023	Electric Depreciation study
New York	New York State Public Service Commission	23-W-0111	Veolia New York	2023	Water Depreciation Study
Arkansas	Arkansas Public Service Commission	22-085-U	Empire District Electric Company	2023	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	TA50-733 (U-21-058)	Cook Inlet Natural Gas Storage Alaska	2023	Focused Study - Communication Equipment
Manitoba Canada	Manitoba Public Utilities Board		Manitoba Hydro Electric	2022	Electric Depreciation Study
Tennessee	Tennessee Public Utility Commission	20-00086	Piedmont Natural Gas	2022	Gas Depreciation Study - 3 State
Texas	Public Utility Commission of Texas	54634	Southwestern Public Service Company	2023	Electric Technical Update
Arkansas	Arkansas Public Service Commission	22-085-U	Liberty Empire Electric Arkansas	2023	Electric Depreciation Study
Florida	Florida Public Service Commission	20220219	People Gas System	2022	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-21329	Michigan Gas Utilities Corporation	2022	Gas Depreciation Study
Dominica	Independent Regulatory Commission		Dominica Electricity Services LTD	2022	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	22-00270-UT	Public Service of New Mexico	2022	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	22-00286-UT	Southwestern Public Service Company	2022	Electric Technical Update

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Minnesota	Minnesota Public Utilities Commission	22-299	Northern States Power-Minnesota	2022	Electric Gas and Common Depreciation Study
California	California Public Utilities Commission	A.22-08-010	Bear Valley Electric	2022	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-21294	SEMCO Gas	2022	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	22-064-U	Liberty Pine Bluff Water	2022	Water Depreciation Study
Colorado	Colorado Public Utilities Commission	22AL-0348G	Atmos Energy	**2022**	**Gas Depreciation Study**
New York	FERC	ER22-2581-000	New York Power Authority	2022	Transmission and General Depreciation Study
South Carolina	South Carolina Public Service Commission	2022-89-G	Piedmont Natural Gas	2022	Natural Gas Depreciation Study
California	California Public Utilities Commission	A.22-007-001	California American Water	2022	Water and Waste Water Depreciation Study
Alaska	Regulatory Commission of Alaska	U-22-034	Chugach Electric Association	2022	Electric Depreciation Study
Georgia	Georgia Public Service Commission	44280	Georgia Power Company	2022	Electric Depreciation Study
California	California Public Utilities Commission	22-005-xxx	San Diego Gas and Electric	2022	Electric Gas and Common Depreciation Study
California	California Public Utilities Commission	22-005-xxx	Southern California Gas	2022	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	22AL-0046G	Public Service of Colorado	2022	Gas Depreciation given potential for climate change
Texas	Public Utility Commission of Texas	53601	Oncor Electric Delivery	2022	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR2222040253	South Jersey Gas	2022	Gas Depreciation Study
Oklahoma	Corporation Commission of Oklahoma	PUD 202100163	Empire District Electric Company	2022	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-21176	Consumers Gas	2021	Gas Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR21121254	Elizabethtown Natural Gas	2021	Gas Depreciation Study
Ontario Canada	Ontario Energy Board	EB-2021-0110	Hydro One	2021	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	TA116-118, TA115-97, TA160-37 and TA110-290	Fairbanks Water and Wastewater	2021	Water and Waste Water Depreciation Study
Colorado	Public Utilities Commission of Colorado	21AL-0317E	Public Service of Colorado	2021	Electric and Common Depreciation Study

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-21-025	Golden Valley Electric Association	2021	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	5-DU-103	WE Energies	2021	Electric and Gas Depreciation Study
Kentucky	Public Service Commission of Kentucky	2021-00214	Atmos Kentucky	2021	Gas Depreciation Study
Missouri	Missouri Public Service Commission	ER-2021-0312	Empire District Electric Company	2021	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-111	Northern States Power Wisconsin	2021	Transmission, Distribution General and Common Depreciation Study
Louisiana	Louisiana Public Service Commission	U-35951	Atmos Energy	2021	Statewide Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015-D-21-229	Allete Minnesota Power	2021	Intangible, Transmission, Distribution, and General Depreciation Study
Michigan	Michigan Public Service Commission	U-20849	Consumers Energy	2021	Electric and Common Depreciation Study
Texas	Texas Public Utility Commission	51802	Southwestern Public Service Company	2021	Electric Technical Update
MultiState	FERC	RP21-441-000	Florida Gas Transmission	2021	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	20-00238-UT	Southwestern Public Service Company	2021	Electric Technical Update
Yukon Territory Canada	Yukon Energy Board	2021 General Rate Application	Yukon Energy	2020	Electric Depreciation Study
MultiState	FERC	ER21-709-000	American Transmission Company	2020	Electric Depreciation Study
Texas	Texas Public Utility Commission	51611	Sharyland Utilities	2020	Electric Depreciation Study
Texas	Texas Public Utility Commission	51536	Brownsville Public Utilities Board	2020	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	WR20110729	Suez Water New Jersey	2020	Water and Waste Water Depreciation Study
Idaho	Idaho Public Service Commission	SUZ-W-20-02	Suez Water Idaho	2020	Water Depreciation Study

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Texas Public Utility Commission	50944	Monarch Utilities	2020	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-20844	Consumers Energy/DTE Electric	2020	Ludington Pumped Storage Depreciation Study
Mexico	Comision Reguladora de Energia	G/352/TRA/2015 UH-250/125738/2019	Arguelles Depreciation Study	2020	Gas Depreciation Study
Tennessee	Tennessee Public Utility Commission	2000086	Piedmont Natural Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	OS-00005136	CoServ Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10988	EPCOR Gas Texas	2020	Gas Depreciation Study
Florida	Florida Public Service Commission	20200166-GU	People Gas System	2020	Gas Depreciation Study
Mississippi	Federal Energy Regulatory Commission	ER20-1660-000	Mississippi Power Company	2020	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50557	Corix Utilities	2020	Water and Waste Water Depreciation Study
Georgia	Georgia Public Service Commission	42959	Liberty Utilities Peach State Natural Gas	2020	Gas Depreciation Study
Texas	Public Utility Commission of Texas	50734	Oncor Electric Delivery	2020	Life of Intangible Plant
New Jersey	New Jersey Board of Public Utilities	GR20030243	South Jersey Gas	2020	Gas Depreciation Study
Kentucky	Kentucky Public Service Commission	2020-00064	Big Rivers	2020	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	20AL-0049G	Public Service of Colorado	2020	Gas Depreciation Study
New York	Federal Energy Regulatory Commission	ER20-716-000	LS Power Grid New York, Corp.	2019	Electric Transmission Depreciation Study
Mississippi	Mississippi Public Service Commission	2019-UN-219	Mississippi Power Company	2019	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50288	Kerrville Public Utility District	2019	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10920	CenterPoint Gas	2019	Gas Depreciation Study and Propane Air Study
Texas, New Mexico	Federal Energy Regulatory Commission	ER20-277-000	Southwestern Public Service Company	2019	Electric Production and General Plant Depreciation Study
New Mexico	New Mexico Public Regulation Commission		New Mexico Gas	2019	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-19-086	Alaska Electric Light and Power	2019	Electric Depreciation Study

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Railroad Commission of Texas	GUD 10900	Atmos Energy West Texas Division - Triangle	2019	Depreciation Rates for Natural Gas Property
Delaware	Delaware Public Service Commission	19-0615	Suez Water Delaware	2019	Water Depreciation Study
California	California Public Utilities Commission	A.19-08-015	Southwest Gas Northern California	2019	Gas Depreciation Study
California	California Public Utilities Commission	A.19-08-015	Southwest Gas Southern California	2019	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10895	CenterPoint Propane Air	2019	Depreciation Rates for Propane Air Assets
Texas	Public Utility Commission of Texas	49831	Southwestern Public Service Company	2019	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	19-00170-UT	Southwestern Public Service Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42516	Georgia Power Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42315	Atlanta Gas Light	2019	Gas Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-19-0055	Southwest Gas Corporation	2019	Gas Removal Cost Study
New Hampshire	New Hampshire Public Service Commission	DE 19-064	Liberty Utilities	2019	Electric Distribution and General
New Jersey	New Jersey Board of Public Utilities	GR19040486	Elizabethtown Natural Gas	2019	Gas Depreciation Study
Texas	Public Utility Commission of Texas	49421	CenterPoint Houston Electric LLC	2019	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket No. G-9, Sub 743	Piedmont Natural Gas	2019	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E-015/D-18-226	Allete Minnesota Power	2018	Electric Compliance Filing
Colorado	Colorado Public Utilities Commission	19AL-0063ST	Public Service of Colorado	2019	Steam Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-121	Municipal Power and Light City of Anchorage	2018	Electric Depreciation Study
Various	FERC	RP19-352-000	Sea Robin	2018	Gas Depreciation Study
Texas New Mexico	Federal Energy Regulatory Commission	ER19-404-000	Southwestern Public Service Company	2018	Electric Transmission Depreciation Study
California	Federal Energy Regulatory Commission	ER19-221-000	San Diego Gas and Electric	2018	Electric Transmission Depreciation Study

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos Kentucky	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48500	Golden Spread Electric Coop	2018	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-054	Matanuska Electric Coop	2018	Electric Generation Depreciation Study
California	California Public Utilities Commission	A17-10-007	San Diego Gas and Electric	2018	Electric and Gas Depreciation Study
Texas	Public Utility Commission of Texas	48401	Texas New Mexico Power	2018	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	18-05031	Southwest Gas	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Depreciation Rates
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-34803	Atmos LGS	2018	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E-015/D-18-226	Allete Minnesota Power	2018	Electric Depreciation Rate
Kentucky	Kentucky Public Service Commission	2017-00349	Atmos KY	2018	Gas Depreciation Rates
Tennessee	Tennessee Public Utility Commission	18-00017	Chattanooga Gas	2018	Gas Depreciation Study
Texas	Railroad Commission of Texas	10679	Si Energy	2018	Gas Depreciation Study
Texas	City of Dallas Statement of Intent	NA	Atmos Mid-Tex	2017-2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-104	Anchorage Water and Wastewater	2017	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-18488	Michigan Gas Utilities Corporation	2017	Gas Depreciation Study
New Mexico	FERC	ER18-228-000	Southwestern Public Service Company	2017	Electric Production Depreciation Study
Texas	Railroad Commission of Texas	10669	CenterPoint South Texas	2017	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	17-00255-UT	Southwestern Public Service Company	2017	Electric Production Depreciation Study
Arkansas	Arkansas Public Service Commission	17-061-U	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Kansas	Kansas Corporation Commission	18-EPDE-184-PRE	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Oklahoma	Oklahoma Corporation Commission	PUD 201700471	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Missouri	Missouri Public Service Commission	EO-2018-0092	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Michigan	Michigan Public Service Commission	U-18457	Upper Peninsula Power Company	2017	Electric Depreciation Study
Florida	Florida Public Service Commission	20170179-GU	Florida City Gas	2017	Gas Depreciation Study
Michigan	FERC	ER18-56-000	Consumers Energy	2017	Electric Depreciation Study
Missouri	Missouri Public Service Commission	GR-2018-0013	Liberty Utilities	2017	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18452	SEMCO	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	47527	Southwestern Public Service Company	2017	Electric Production Depreciation Study
Minnesota	Minnesota Public Utilities Commission	17-581	Minnesota Northern States Power	2017	Electric, Gas and Common Transmission, Distribution and General
Colorado	Colorado Public Utilities Commission	17AL-0363G	Public Service of Colorado-Gas	2017	Gas Depreciation Study
MultiState	FERC	ER17-1664	American Transmission Company	2017	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-008	Municipal Power and Light City of Anchorage	2017	Generating Unit Depreciation Study
Louisiana	Louisiana Public Service Commission	U-34343	Atmos Trans Louisiana	2017	Gas Depreciation Study
Mississippi	Mississippi Public Service Commission	2017-UN-041	Atmos Energy	2017	Gas Depreciation Study
New York	FERC	ER17-1010-000	New York Power Authority	2017	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD 201700078	CenterPoint Oklahoma	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10580	Atmos Pipeline Texas	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	46957	Oncor Electric Delivery	2017	Electric Depreciation Study
Alabama	FERC	ER16-2312-000	Alabama Power Company	2016	Electric Depreciation Study
Alabama	FERC	ER16-2313-000	SEGCO	2016	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-16-067	Alaska Electric Light and Power	2016	Generating Unit Depreciation Study

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Arizona	Arizona Corporation Commission	G-01551A-16-0107	Southwest Gas	2016	Gas Depreciation Study
California	California Public Utilities Commission	A 16-07-002	California American Water	2016	Water and Waste Water Depreciation Study
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service Company of Colorado	2016	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	2016 UN 267	Willmut Gas	2016	Gas Depreciation Study
Florida	Florida Public Service Commission	160170-EI	Gulf Power	2016	Electric Depreciation Study
Georgia	N/A	N/A	Dalton Utilities	2016	Electric, Gas, Water, Wastewater & Fiber Depreciation Study
Illinois	Illinois Commerce Commission	GRM #16-208	Liberty-Illinois	2016	Natural Gas Depreciation Study
Iowa	Iowa Utilities Board	RPU-2016-0003	Liberty-Iowa	2016	Natural Gas Depreciation Study
Kentucky	FERC	RP16-097-000	KOT	2016	Natural Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18195	Consumers Energy/DTE Electric	2016	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-18127	Consumers Energy	2016	Natural Gas Depreciation Study
MultiState	FERC	ER17-191-000	American Transmission Company	2016	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR16090826	Elizabethtown Natural Gas	2016	Gas Depreciation Study
New York	NA		New York Power Authority	2016	Electric Transmission and General Study
North Carolina	North Carolina Utilities Commission	Docket G-9 Sub 77H	Piedmont Natural Gas	2016	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10567	CenterPoint Texas	2016	Gas Depreciation Study
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint- Texas Coast Division	2015	Gas Depreciation Study
Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study
Texas, New Mexico	FERC	ER15-949-000	Southwestern Public Service Company	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Alabama	State of Alabama Public Service Commission	U-5115	Mobile Gas	2014	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study
Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service Company of Colorado	2014	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-28814	Atmos Energy Corporation	2014	Gas Depreciation Study

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Michigan	Michigan Public Service Commission	U-17653	Consumers Energy Company	2014	Electric and Common Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	14-00332-UT	Public Service of New Mexico	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43695	Southwestern Public Service Company	2014	Electric Depreciation Study
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies
Texas, New Mexico	Public Utility Commission of Texas	42004	Southwestern Public Service Company	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Virginia	Virginia Corporation Commission	PUE-2013-00124	Atmos Energy Corporation	2013-2014	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-079-U	Source Gas Arkansas	2013	Gas Depreciation Study
California	California Public Utilities Commission	Proceeding No.: A.13-11-003	Southern California Edison	2013	Electric Depreciation Study
Kentucky	Kentucky Public Service Commission	2013-00148	Atmos Energy Corporation	2013	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	13-252	Allete Minnesota Power	2013	Electric Depreciation Study
New Hampshire	New Hampshire Public Service Commission	DE 13-063	Liberty Utilities	2013	Electric Distribution and General
New Jersey	New Jersey Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
North Carolina/South Carolina	FERC	ER13-1313	Progress Energy Carolina	2013	Electric Depreciation Study
Texas	Public Utility Commission of Texas	41474	Sharyland	2013	Electric Depreciation Study
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power Company - Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1269ST	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1268G	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Northern States Power Company - Minnesota	2012	Electric, Gas and Common Transmission, Distribution and General
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	Southwestern Public Service Company	2012	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
North Dakota	North Dakota Public Service Commission	PU-12-0813	Northern States Power	2012	Electric, Gas and Common Transmission, Distribution and General
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Railroad Commission of Texas	10174	Atmos West Texas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10182	CenterPoint Beaumont/ East Texas	2012	Gas Depreciation Study
Texas	Texas Public Utility Commission	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40020	Lone Star Transmission	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40824	Xcel Energy	2012	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service Company of Colorado	2011	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study
Mississippi	Mississippi Public Service Commission	2011-UN-184	Atmos Energy	2011	Gas Depreciation Study
MultiState	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study
MultiState			Atmos Energy	2011	Shared Services Depreciation Study
Pennsylvania	NA	NA	Safe Harbor	2011	Hydro Depreciation Study
Texas	Texas Public Utility Commission	39896	Entergy Texas	2011	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Texas Commission on Environmental Quality	Matter 37050-R	Southwest Water Company	2011	WasteWater Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Multistate	NA	NA	Constellation Energy Nuclear	2010	Nuclear Generation Depreciation Study
Texas	Texas Railroad Commission	10041	Atmos Amarillo	2010	Gas Depreciation Study

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Texas Railroad Commission	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service Company	2010	Electric Technical Update
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study
California	California Public Utility Commission	A10071007	California American Water	2009-2010	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Wyoming	Wyoming Public Service Commission	30022-148-GR10	Source Gas	2009-2010	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service of Colorado	2009	Electric Depreciation Study
Iowa	NA		Cedar Falls Utility	2009	Telecommunications, Water, and Cable Utility
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Michigan	Michigan Public Service Commission	In Progress	Edison Sault	2009	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study
New York	New York Public Service Commission		Key Span	2009	Generation Depreciation Study
North Carolina	North Carolina Utilities Commission		Piedmont Natural Gas	2009	Gas Depreciation Study
Tennessee	Tennessee Regulatory Authority	09-000183	AGL – Chattanooga Gas	2009	Gas Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study
Multiple States	NA	NA	Constellation Energy	2008	Generation Depreciation Study
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	Southwestern Public Service Company	2008	Testimony – Depreciation

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power Company - Minnesota	2008	Net Salvage
Texas	Public Utility Commission of Texas	35763	Southwestern Public Service Company	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Colorado	Colorado Public Utilities Commission	Filed – no docket to date	Public Service Company of Colorado	2007-2008	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	10AL-963G	Public Service Company of Colorado	2007-2008	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study
Multiple States	NA	NA	Constellation Energy	2007	Generation Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study
Multiple States	Multiple	NA	CenterPoint Energy	2006	Shared Services Depreciation Study

WORKPAPERS

TO

DIRECT TESTIMONY

OF

DANE A. WATSON

Workpapers to the Direct Testimony of Dane A. Watson are voluminous and are being provided in electronic format.

CASE NO. 00017816

STATEMENT OF INTENT OF WEST TEXAS GAS UTILITY, LLC TO INCREASE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF TEXAS	§ § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

BRUCE H. FAIRCHILD

ON BEHALF OF

WEST TEXAS GAS UTILITY, LLC

July 16, 2024

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 CAPACITY?

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 resumé that contains the details of my experience and qualifications is attached as Appendix A, with Appendix B listing my prior testimony before regulatory agencies since leaving the PUCT.

B. Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is three-fold. First, I sponsor the revenue requirements, or total cost of providing service, for West Texas Gas Utility, LLC's ("WTGU") natural gas distribution operations in Texas. Second, I perform the class cost-of-service study ("COSS") that allocates WTGU's total Texas revenue requirements between its Jurisdictional Domestic and Non-Domestic customers and its Non-Jurisdictional customers. Third, I develop a fair rate of return to apply to WTGU's invested capital, or rate base, to be used to determine its cost of providing service in this case and for subsequent interim rate adjustments.

Q. WHAT GUIDED YOUR DEVELOPMENT OF WTGU'S REVENUE REQUIREMENTS AND COSS?

A. The Rate Filing Schedules in this filing are generally patterned after those in GUD No. 10235 and Docket No. OS-20-00004347, which are the last two rate cases filed by West Texas Gas, Inc., WTGU's predecessor. Those filings followed closely the *Gas Services Division's Suggested "Best Practices" for Preparing a Statement of Intent Proposing a Rate Increase Considered a 'Major Change.'* As in Docket No. OS-20-00004347, I streamlined the Rate Filing Schedules by combining and simplifying a number of schedules and omitting others that are not applicable, and I believe they contain virtually all of the same information.

Q. WHAT SCHEDULES AND EXHIBITS ARE YOU SPONSORING?

A I am sponsoring or co-sponsoring all of the schedules in the Rate Filing Schedules except those related to the Gas Reliability Infrastructure Program ("GRIP"), payroll, certain expense information, and affiliates. These are identified in the Table of Contents to the Rate Filing Schedules. I am also sponsoring Exhibits BHF-1 through BHF-11 attached to this testimony, which are related to rate of return.

C. Summary

Q. WOULD YOU BRIEFLY SUMMARIZE THE RESULTS OF YOUR REVENUE REQUIREMENTS AND COSS ANALYSES?

A. As shown on Schedule A, WTGU's Texas revenue requirements, excluding gas costs, total $34,616,294. This amount is based on a test year ended December 31, 2023, with Schedule A-3 summarizing the adjustments made to test year amounts. Based on a COSS allocating Texas revenue requirements between customer classes, I determined that $20,367,710 and $6,098,421 are attributable to WTGU's

Jurisdictional Domestic and Non-Domestic customers, respectively, with the remainder being attributable to its Non-Jurisdictional customers. As shown at the bottom of Schedule A, these Jurisdictional class revenue requirements represent an increase over current revenues, which include WTGU's requested GRIP charge pending before the Railroad Commission of Texas ("Commission"), of $10,183,324, or 100.0%, for Domestic customers, and $3,005,446, or 102.9%, for Non-Domestic customers.

Q. WHAT COST-BASED RATES RESULT FROM THESE TWO JURISDICTIONAL CLASS REVENUE REQUIREMENTS?

A. Monthly customer charges and Mcf consumption charges for Jurisdictional Domestic and Non-Domestic customers based on their respective class revenue requirements of $20,367,710 and $6,098,421 are developed on Schedule A-1. As shown there, cost-based rates for Domestic customers are a $71.63 per month customer charge and $4.67 per Mcf, and, for Non-Domestic customers, an $82.89 per month customer charge and $9.61 per Mcf.

Q. HOW DO THESE COST-BASED RATES FOR WTGU'S JURISDICTIONAL CUSTOMERS COMPARE TO CURRENT RATES?

A. Schedule A-2 and the following table compare WTGU's current rates, which include WTGU's pending requested GRIP charge, for Domestic and Non-Domestic customers with cost-based rates:

Description	Current Rates	Cost-Based Rates	Percentage Change
Domestic Customers			
Customer Charge	$ 23.42	$ 71.63	205.8%
Commodity Charge (Mcf)	$ 4.84	$ 4.67	-3.6%
Non-Domestic Customers			
Customer Charge	$ 43.57	$ 82.89	90.2%
Commodity Charge (Mcf)	$ 2.69	$ 9.61	257.4%

Q. IS WTGU REQUESTING THAT THE COMMISSION APPROVE THESE COST-BASED RATES?

A. No. Because of the overall magnitude of the increases required to charge cost-based rates and the distortions to the structure of existing rates, WTGU is requesting that the Commission approve rates for Domestic customers consisting of a $29.50 monthly customer charge and a $7.68 per Mcf consumption charge, and, for Non-Domestic customers, a monthly customer charge of $79.00 and a consumption charge of $4.89 per Mcf. These requested rates are compared to existing rates in the following table and on Schedule A-2:

Description	Current Rates	Requested Rates	Percentage Change
Domestic Customers			
Customer Charge	$ 23.42	$ 29.50	26.0%
Commodity Charge (Mcf)	$ 4.84	$ 7.68	58.7%
Non-Domestic Customers			
Customer Charge	$ 43.57	$ 79.00	81.3%
Commodity Charge (Mcf)	$ 2.69	$ 4.89	81.8%

As shown at the bottom of Schedule A, WTGU's requested rates represent an increase in revenues from Domestic customers of $4,327,298, or 42.5%, and from Non-Domestic customers of $2,451,592, or 81.6%.

II. REVENUE REQUIREMENTS

Q. HOW DID YOU DETERMINE WTGU'S TEXAS REVENUE REQUIREMENTS?

A. The cost of providing service on the WTGU system was based on the conventional revenue requirements formula of:

Revenue Requirements = Operation & Maintenance Expenses + Administrative & General Expenses + Taxes Other than Income + Depreciation Expense + Return (Rate of Return X Rate Base) + Income Tax Expense – Other Income

The test year used as the basis for measuring the components of the revenue requirements formula was the twelve months ended December 31, 2023. I obtained the financial and operating data used to develop WTGU's revenue requirements from WTGU's books and records sponsored by WTGU witness Amanda Edgmon. As will be explained in more detail subsequently, I made a number of adjustments to WTGU's actual expenses, investment, and operating data during the test year to conform to accepted ratemaking practices and the policies of the Commission and to remove amounts related to Oklahoma operations.

A. Operation and Maintenance Expenses

Q. WHAT OPERATIONS AND MAINTENANCE ("O&M") EXPENSES DID WTGU INCUR DURING THE TEST YEAR?

A. As shown on Schedule B-1 by Federal Energy Regulatory Commission ("FERC") account, WTGU incurred O&M expenses excluding gas costs, which are accounted for separately through WTGU's Gas Cost Adjustment ("GCA"), during 2023 totaling $12,201,412. These O&M expenses are broken out by month on Schedule B.

Q. WERE ANY ADJUSTMENTS MADE TO TEST YEAR O&M EXPENSES?

A. Yes. Account 858, Transmission and Compression of Gas by Others, is included in the cost of gas in WTGU's GCA for Texas customers. Therefore, the $347,264 in Account 858 was removed to avoid double counting this expense. Additionally, $26,370 in donations and contributions included in Account 880, Other Expenses, was also removed pursuant to the Commission's rules.

Q. WERE ANY OTHER ADJUSTMENTS MADE TO TEST YEAR O&M EXPENSES?

A. Yes. Because WTGU serves customers in both Texas and Oklahoma, it is necessary to remove amounts attributable to Oklahoma operations to calculate the cost of providing service in Texas. Accordingly, a share of the total O&M expenses in WTGU's Regions 40 and 70, the two regions that operate in both states, was allocated to Oklahoma in proportion to the number of customers served in the state relative to the total number of customers in each region. The details of this allocation are shown on Schedule B-4. The amounts in each FERC account, which total $1,131,411, were then deducted from WTGU's total O&M expenses in the column labeled "Oklahoma" on Schedule B-1, with the remaining O&M expenses being attributable to Texas operations.

Q. DID YOU MAKE ANY ADJUSTMENTS TO O&M EXPENSES FOR CHANGES IN PAYROLL COSTS?

A. No. Per discussions with WTGU management, there were no material changes in WTGU's personnel or their salaries during or subsequent to the test year that warranted making adjustments to the test year payroll costs included in O&M expenses.

Q. AFTER MAKING THE ADJUSTMENTS DESCRIBED ABOVE, WHAT O&M EXPENSES ARE INCLUDED IN WTGU'S TEXAS REVENUE REQUIREMENTS?

A. The adjusted O&M expenses of $10,696,368 shown at the bottom of Schedule B-1 are included in Texas revenue requirements on Schedule A.

B. Administrative and General Expenses

Q. WHAT ADMINISTRATIVE AND GENERAL ("A&G") EXPENSES WERE INCURRED BY WTGU DURING THE TEST YEAR?

A. As shown on Schedule B-2 by FERC account, WTGU recorded A&G expenses during 2023 totaling $6,433,393. These A&G expenses are also broken out by month on Schedule B.

Q. WHAT WAS THE FIRST ADJUSTMENT YOU MADE TO TEST YEAR A&G EXPENSES?

A. WTGU records interest on customer deposits in a below-the-line account, but, as will be discussed later, customer deposits are deducted from rate base. So that both of these related items are accounted for in revenue requirements, the $30,504 in interest expense on customer deposits during the test year was reclassified and included in Account 910, Miscellaneous Customer Service Expenses.

Q. WHAT OTHER ADJUSTMENTS WERE MADE TO TEST YEAR A&G EXPENSES?

A. Pursuant to the Commission's rules, amounts paid during 2023 for penalties and fines (Schedule H-7), lobbying expenses (Schedule H-6), and donations and contributions (Schedule H-5) were removed from Account 921, Office Supplies and Expenses, Account 923, Outside Services Employed, and Account 930, Miscellaneous General Expenses, respectively. Also, all entertainment, meals, lodging, and travel expenses were removed from Accounts 921 and 930. These adjustments total $274,847.

Q. WERE THERE ANY OTHER ADJUSTMENTS MADE TO TEST YEAR A&G EXPENSES?

A. Yes. As with O&M expenses, a portion of WTGU's A&G expenses are properly allocated to Oklahoma operations. This allocation is also developed in Schedule B-4. A&G expenses incurred in Regions 40 and 70 were again allocated to Oklahoma in proportion to the number of customers served in the state to the total in each region, while corporate A&G expenses were allocated to Oklahoma using a four-factor allocator that weighted equally the number of customers, gross plant, O&M expenses, and revenues in the state relative to the WTGU totals. The $612,508 of A&G expenses determined on Schedule B-4 as being attributable to Oklahoma operations was deducted from adjusted A&G expenses in the column labeled "Oklahoma" on Schedule B-2, with the remaining A&G expenses being attributable to Texas operations.

Q. AFTER MAKING THE ADJUSTMENTS DESCRIBED ABOVE, WHAT A&G EXPENSES ARE INCLUDED IN WTGU'S TEXAS REVENUE REQUIREMENTS?

A. The adjusted A&G expenses of $5,576,542 shown at the bottom of Schedule B-2 are included in Texas revenue requirements on Schedule A.

C. Taxes Other than Income

Q. WHAT TAXES OTHER THAN INCOME WERE INCURRED BY WTGU DURING THE TEST YEAR?

A. Shown by month on Schedule B and in total on Schedule B-3, WTGU recorded taxes other than income, which consist of payroll taxes, property taxes, and state taxes during 2023 totaling $3,218,888.

Q. WERE ANY ADJUSTMENTS MADE TO THIS TEST YEAR TOTAL?

A. Yes. Except for the Texas Franchise Tax, which was assigned directly to Texas operations, a share of payroll, property, and remaining state taxes was allocated to Oklahoma operations using the four-factor allocator described earlier. As developed on Schedule B-4, this resulted in $426,667 in taxes other than income being attributable to Oklahoma, which were removed from the adjusted total.

Q. AFTER MAKING THE ADJUSTMENTS DESCRIBED ABOVE, WHAT TAXES OTHER THAN INCOME ARE INCLUDED IN WTGU'S TEXAS REVENUE REQUIREMENTS?

A. The adjusted taxes other than income of $2,792,222 shown at the bottom of Schedule B-3 are included in Texas revenue requirements on Schedule A.

D. Rate Base

Q. BRIEFLY DESCRIBE THE CALCULATION OF RATE BASE FOR WTGU.

A. Rate base is the amount on which a utility is entitled to earn a fair rate of return. The rate base for WTGU, which is developed on Schedule C, consists of its net investment in assets used to serve Texas customers less adjustments for non-investor supplied capital. WTGU's net plant investment is calculated by subtracting accumulated depreciation from the original cost of used and useful plant in service at test year-end. Also included in rate base is WTGU's inventory in materials and supplies. Meanwhile, customer deposits, contributions in aid of construction ("CIACs"), and accumulated deferred income taxes ("ADIT"), which are all regarded as sources of non-investor supplied capital, serve to reduce WTGU's rate base.

Q. WHAT WAS WTGU'S PLANT IN SERVICE AT DECEMBER 31, 2023?

A. The total amount of plant in service recorded on WTGU's books at test year-end by FERC account is shown in the first numerical column on Schedule C-1 and totals $291,649,056.

Q. WERE ANY ADJUSTMENTS MADE TO THIS TEST YEAR-END PLANT IN SERVICE?

A. Yes. The first adjustment was to remove plant used to serve Oklahoma customers. Plant located in Oklahoma was identified from WTGU's plant accounting records and deducted in the column on Schedule C-1 labeled "Oklahoma-Direct." Also, a portion of WTGU's corporate plant was allocated to Oklahoma operations based on the proportion of Oklahoma plant to total plant, with the details being contained in footnote (b). Deducting the approximately $19.2 million in direct and allocated plant attributable to Oklahoma operations from the total resulted in approximately $272.5 million being related to Texas service.

Q. WERE ANY ADJUSTMENTS MADE TO TEXAS PLANT IN SERVICE?

A. Yes. Several acquisition adjustments, which reflect amounts paid above the original cost of plant, related to assets previously acquired by WTGU are recorded on its books. Although Section 104.053 of the Texas Utilities Code allows for a utility to earn a return on the adjusted value of invested capital, only the net original cost of property, plant, and equipment at the time it was dedicated to public use is considered in the present case. Accordingly, the acquisition adjustments recorded on WTGU's books were removed.

Q. WHAT OTHER ADJUSTMENTS WERE MADE TO TEXAS PLANT IN SERVICE?

A. Identified in the "Reference" column as (c), (d), (e) and (f), several adjustments were made to remove some relatively minor non-utility assets from WTGU's books and to implement recommendations by WTGU witness Dane Watson noted in his depreciation study. These consisted of reclassifying assets from Account No. 366 (Transmission Structures and Improvements) to Account No. 369 (Transmission Measuring & Regulating Equipment), and reclassifying certain assets in Account Nos. 392 (Transportation Equipment) and 394 (Tools, Shop & Garage) to a new account on WTGU's books, Account No. 396 (Power Operated Equipment). Additionally, adjustments were made to remove various general plant assets that had been retired but were still carried on WTGU's books at test year-end.

Q. ONCE THE ADJUSTMENTS DESCRIBED ABOVE WERE MADE, WHAT IS WTGU'S ADJUSTED TEXAS PLANT IN SERVICE AT TEST YEAR-END?

A. As shown in the last column of Schedule C-1, after removing plant related to Oklahoma operations, acquisition adjustments, non-utility plant, and implementing Mr. Watson's recommendations, WTGU's adjusted Texas plant in service at December 31, 2023 totals $249,166,612, which is included in Texas rate base on Schedule C.

Q. WERE ANY POST-TEST YEAR ADJUSTMENTS MADE TO PLANT IN SERVICE?

A. No.

Q. WHAT ACCUMULATED DEPRECIATION IS RELATED TO WTGU'S TEXAS PLANT IN SERVICE?

A. Schedule C-2 develops the accumulated depreciation associated with the approximately $249.2 million of Texas plant in service developed on Schedule C-1. Beginning with WTGU's depreciation reserve at December 31, 2023, of $87,190,168, corresponding adjustments were made to remove accumulated depreciation and amortization associated with assets related to Oklahoma operations, acquisition adjustments, and non-utility plant, and to include Mr. Watson's recommended adjustments. This resulted in the adjusted Texas accumulated depreciation balance shown on Schedule C-2 of $72,990,047, which is then included in Texas rate base on Schedule C.

Q. WHAT NET PLANT IS INCLUDED IN WTGU'S TEXAS RATE BASE?

A. As shown on Schedule C, deducting adjusted accumulated depreciation of $72,990,047 from adjusted plant in service of $249,166,612 produces Texas net plant in service of $176,176,565.

Q. WAS ANY CONSTRUCTION WORK IN PROGRESS ("CWIP") INCLUDED IN WTGU'S TEXAS RATE BASE?

A. No. Although WTGU had approximately $5.4 million invested in CWIP at test year-end, this plant under construction is not included in Texas rate base.

Q. WAS A CASH WORKING CAPITAL ALLOWANCE INCLUDED IN WTGU'S TEXAS RATE BASE?

A. No. As in its last two rate cases, GUD No. 10235 and Docket No. OS-20-00004347, WTGU is not requesting a cash working capital allowance be included in Texas rate base.

Q. WERE ANY OTHER WORKING CAPITAL ITEMS INCLUDED IN WTGU'S TEXAS RATE BASE?

A. Yes. WTGU prepays certain expenses and maintains inventories of materials and supplies used in connection with the operation and maintenance of its system. As shown in Schedule C-3, WTGU's prepayments and materials and supplies inventories at test year-end were $1,016,495 and $1,963,405, respectively. Two adjustments were made to these balances. The first was to remove a portion of prepayments and inventories attributable to Oklahoma operations based on Oklahoma plant as a percent of total WTGU plant. The second was to adjust the test year-end materials and supplies balance to an average balance over the test year, as is customary ratemaking practice. After making these two adjustments, average prepayments of $1,181,498 and materials and supplies inventory of $1,851,614 shown on Schedule C-3 are included in Texas rate base on Schedule C.

Q. PLEASE DESCRIBE THE CUSTOMER DEPOSITS AND CIACS SHOWN ON SCHEDULE C.

A. At December 31, 2023, WTGU had $1,508,997 in customer deposits and $23,804,581 in net CIACs recorded as credits on its books. As noted earlier, customer deposits and CIACs are regarded as sources of non-investor supplied capital and serve to reduce rate base.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THESE TEST YEAR-END AMOUNTS?

A. Yes. Some of the customer deposits and CIACs were provided by customers in Oklahoma. These amounts were removed from the test year-end totals on Schedule C, resulting in $1,200,560 in customer deposits and $23,143,350 in net CIACs being deducted from Texas rate base.

Q. WHAT ADIT ARE ASSOCIATED WITH WTGU'S ADJUSTED TEST YEAR-END PLANT IN SERVICE?

A. As a limited liability company, WTGU does not record income tax-related items on its books. However, consistent with Section 104.055(c) of the Texas Utilities Code, a federal income tax allowance is included in WTGU's revenue requirements. Correspondingly, ADIT for WTGU should be calculated and reflected for ratemaking purposes.

Q. DID YOU CALCULATE ADIT FOR WTGU AT DECEMBER 31, 2023?

A. Yes. ADIT for utilities is primarily attributable to the tax benefits arising from the use of accelerated depreciation methods for tax purposes (including "bonus" depreciation allowed on construction beginning in 2008) versus the straight-line depreciation used for ratemaking purposes. In footnote (e) of Schedule C, total ADIT at December 31, 2023 was calculated by multiplying the difference between WTGU's net plant in service and its net tax basis of plant in service times the current corporate federal income tax rate of 21%. The resulting total ADIT liability was then multiplied by the ratio of adjusted Texas plant in service to total plant in service to remove ADIT associated with Oklahoma plant, acquisitions adjustments, non-utility plant, and retired plant. This resulted in a Texas test year-end ADIT liability of $35,774,897. Offsetting this ADIT liability is an ADIT asset attributable to CIACs being taxable when they are received but amortized over their useful life for ratemaking purposes. Multiplying the Texas net CIACs at test year-end of $23,143,350 described earlier by a 21% tax rate produced an ADIT asset of $4,860,104. Subtracting the Texas ADIT asset from the Texas ADIT liability resulted in a net Texas ADIT liability of $25,703,718, which is deducted from Texas rate base on Schedule C.

Q. WHAT IS THE AMOUNT LABELED "EXCESS ADIT" AT THE BOTTOM OF SCHEDULE C?

A. Effective January 1, 2018, the federal corporate income tax rate decreased from 35% to 21%, and ADIT liability and asset amounts dropped correspondingly. Whereas unregulated firms removed the reductions in ADIT, regulatory authorities, including the Commission, required that the ADIT attributable to the reduction in the corporate income tax rate continued to be carried on a gas utility's books as "excess ADIT." It is then to be amortized over a period generally corresponding to the remaining lives of the assets that gave rise to the excess ADIT.

Q. WHAT IS THE EXCESS ADIT FOR WTGU AT TEST YEAR-END?

A. The excess ADIT at December 31, 2017 was determined in Docket No. OS-20-00004347 to be $11,836,559, with the ratable amortization of the excess being $420,839 per year. These calculations are shown in Schedule C-4. At the bottom of Schedule C-4, the excess ADIT is reduced by the six years of amortization between 2018 and 2023 to calculate the net excess ADIT at December 31, 2023 of $9,311,525, which is deducted from Texas rate base on Schedule C.

Q. WHAT IS WTGU'S TEXAS RATE BASE?

A. Summing the adjusted Texas net plant and working capital, and deducting non-investor supplied capital, all as discussed above, results in Texas rate base of $119,850,523, as shown at the bottom of Schedule C.

E. Depreciation Expense

Q. WHAT DEPRECIATION EXPENSE DID WTGU ACCRUE DURING THE TEST YEAR?

A. During 2023, WTGU booked net depreciation and amortization expense totaling $6,112,656. This includes depreciation and amortization expense on Oklahoma plant, intangible plant, CIACs, and plant in service for only a partial year. On Schedule D, the depreciation rates approved in Docket No. OS-20-00004347 are applied to the test year-end adjusted Texas plant balances developed in Schedule C-1, which produces annual depreciation expense of $5,867,672.

Q. IS THIS THE DEPRECIATION EXPENSE INCLUDED IN WTGU'S TEXAS REVENUE REQUIREMENTS?

A. No. Mr. Watson is recommending revised depreciation rates for WTGU. In the last column of Schedule D, Mr. Watson's recommended depreciation rates for each FERC plant account are applied to WTGU's adjusted Texas plant balances to calculate depreciation expense by plant account. The sum of the plant depreciation expenses, less the amortization of CIACs, produces net adjusted depreciation expense of $5,211,043, which is included in Texas revenue requirements on Schedule A.

F. Return on Investment and Income Taxes

Q. WHAT RATE OF RETURN IS WTGU REQUESTING?

A. Developed in the last section of my testimony and on Schedule E, WTGU is requesting an overall rate of return of 8.10% be used to determine its cost of providing service in this case and in subsequent GRIP filings. This rate of return is based on capital structure ratios of 34.40% debt and 65.60% equity, a cost of debt of 3.06%, and a rate of return on equity of 10.75%.

Q. WHAT RETURN ON INVESTMENT IS INCLUDED IN WTGU REVENUE REQUIREMENTS?

A. As shown in the upper portion of Schedule F, multiplying WTGU's Texas rate base of $119,850,523 from Schedule C by its requested 8.10% overall rate of return from Schedule E produces a return on investment of $9,713,453. These same calculations are also shown on Schedule A, where the $9,713,453 return on investment is included in Texas revenue requirements.

Q. WHAT FEDERAL INCOME TAXES ARE ASSOCIATED WITH THIS RETURN?

A. As developed in the middle of Schedule F, the after-tax equity return included in WTGU's requested return on investment is $8,451,859. This amount is reduced by the $420,839 annual ratable amortization of excess ADIT developed in Schedule C-4 to arrive at an adjusted after-tax equity return of $8,031,020. Multiplying this adjusted after-tax equity return by a gross-up factor of 1.265823 (i.e., 1 / (1 – income tax rate)) produces taxable income of $10,165,848. This taxable income is then multiplied by the statutory corporate tax rate of 21% to calculate an income tax expense of $2,134,828.

Q. IS THIS THE INCOME TAX EXPENSE INCLUDED IN WTGU'S REVENUE REQUIREMENTS?

A. No. This income tax expense is reduced by the ratable amortization of excess ADIT so as to credit this annual amortization amount to determine cost of service rates. Accordingly, reducing the income tax expense of $2,134,828 by the annual amortization calculated on Schedule C-4 of $420,839 results in a net income tax expense of $1,713,989, which is included in Texas revenue requirements on Schedule A.

G. Other Income

Q. WHAT OTHER INCOME DID WTGU RECEIVE DURING THE TEST YEAR?

A. Summarized on Schedule G-1 and shown by month on Schedule G, WTGU received income from other services and activities during calendar year 2023 totaling $1,293,066. The only adjustments to this other income were to remove amounts attributable to Oklahoma operations. As shown on Schedule G-1, sources of other income that could be identified with Oklahoma were removed directly, with a portion of the other income that was received in both states being allocated to Oklahoma based on the 16.32% customer percentage shown on Schedule B-4.

Q. WHAT OTHER INCOME IS DEDUCTED FROM WTGU'S TEXAS REVENUE REQUIREMENTS?

A. After removing direct and allocated other income attributable to Oklahoma, the remaining other income shown at the bottom of Schedule G-1 of $1,087,324 is deducted from Texas revenue requirements on Schedule A.

H. Total Revenue Requirements

Q. WHAT ARE WTGU'S TOTAL TEXAS REVENUE REQUIREMENTS?

A. As summarized on Schedule A under the heading "Adjusted Texas Amounts," summing the O&M expenses, A&G expenses, taxes other than income, depreciation expense, return on investment, income taxes, and other income developed above produces revenue requirements, or a total cost of service, for WTGU's Texas customers of $34,616,294.

III. COST OF SERVICE STUDY

A. Overview

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. The purpose of this section is to present a COSS that allocates WTGU's Texas revenue requirements, developed on Schedule A, between its Jurisdictional Domestic and Non-Domestic customer classes, and its Non-Jurisdictional customer class. The results of the COSS provide the basis to develop cost-based rates for WTGU's Jurisdictional Domestic and Non-Domestic customers.

Q. WOULD YOU BRIEFLY DESCRIBE A COSS?

A. A COSS is an engineering, accounting, and economic analysis designed to allocate a utility's total cost of providing service to specific customers or customer classes. Although some operating and capital costs can be attributed to one or more specific customer classes, most of a utility's operating expenses, except gas costs, and capital investment is incurred to serve all customers, to a greater or lesser extent. Because the joint and common costs cannot be directly tied to specific customers or customer classes, they must be apportioned among all customers and/or customer classes. This apportionment and assignment is accomplished through a COSS, in which operating, and capital costs are allocated using factors developed from various operating data reflecting cost causation. The sum of the costs allocated to each customer and/or customer class in the COSS represents class revenue requirements, or that portion of the utility's total costs for which a particular customer or customer class is responsible.

Q. WHAT GUIDED YOUR COSS?

A. The COSS follows the methodology used to allocate costs between customer classes in WTGU's last two rate cases, with two exceptions. The first relates to the identification of plant between that used to serve all customers ("Joint"), only Jurisdictional customers ("Jurisdictional"), or only Non-Jurisdictional customers ("Non-Jurisdictional"). The second relates to the minimum size of pipe used to classify certain plant and accumulated depreciation between customer- and capacity-related costs. Other than these two exceptions, which I discuss more below, the Texas operating expenses and capital costs developed earlier to calculate

Texas revenue requirements are classified and allocated in the same way as in GUD No. 10235 and Docket No. OS-20-00004347.

Q. WHAT WAS THE INITIAL STEP IN CONDUCTING THE COSS?

A. The first step was to identify the amount of each component comprising WTGU's Texas revenue requirements of $34,616,294. The first numerical column of Schedule J-1 provides the detail of each item of WTGU's Texas revenue requirements, including rate base (i.e., plant in service, accumulated depreciation, working capital items, non-investor supplied capital), operating expenses (i.e., O&M, A&G, and taxes other than income), capital costs (i.e., depreciation expense, return on investment, and net income taxes), and other income by FERC account and dollar amount. As shown on page 2 of 4 of Schedule J-1, the rate base components in the COSS sum to the $119,850,523 developed on Schedule C, and on page 3 of 4, the components of revenue requirements sum to the total on Schedule A of $34,616,294.

Q. WHAT WAS THE NEXT STEP IN CONDUCTING THE COSS?

A. In the COSS in GUD No. 10235 and Docket No. OS-20-00004347, all of WTGU's investment in property, plant, and equipment was treated as joint and common (i.e., used to serve all customers), with a portion of all plant being allocated to both Jurisdictional and Non-Jurisdictional customers. As explained in the testimonies of Ms. Edgmon and Jack J. King, this treatment ignores that much of WTGU's dispersed investment can be specifically identified with serving only Jurisdictional or only Non-Jurisdictional customers. Aside from WTGU not recovering the full cost of investment discussed by Mr. King, the failure to recognize in the COSS that specific plant amounts were incurred to serve, and only benefit, certain customers violates the fundamental ratemaking principle that customers causing a cost should pay for that cost, and that a customer's rates should reflect only the costs incurred to serve that customer. Conversely, allocating a portion of the costs incurred to serve only one class of customers (e.g., jurisdictional) to another class (e.g., non-jurisdictional) results in cross-subsidizations between the classes. To remedy the distortions and unintended consequences of treating all plant as Joint and to allocate WTGU's costs among its customers more accurately, I modified the prior COSS and assigned plant identified as being used to serve only a particular customer class directly to that class.

Q. HOW WAS THIS DONE?

A. Ms. Edgmon reviewed each WTGU plant addition since 2014. Those additions that served only Jurisdictional and only Non-Jurisdictional customers were identified as such, with the remaining post-2014 additions and all investment prior to 2014 being considered Joint plant. She then determined the total cost and associated accumulated depreciation at test year-end of the 2014-2023 Jurisdictional and Non-Jurisdictional plant additions. These are shown in the third and fourth columns on Schedule J-1, with the second column reflecting the cost and accumulated depreciation of all other plant treated as Joint.

B. Cost Classification

Q. WHAT WAS THE NEXT STEP IN THE COSS?

A. Having identified the components of revenue requirements, including Joint, Jurisdictional, and Non-Jurisdictional plant and accumulated depreciation, the next step was to determine what portion of each item of the revenue requirements is customer-related, capacity-related, and/or commodity-related. Because WTGU's Texas revenue requirements exclude gas costs, which are recovered separately through its GCA, no portion of its costs are commodity-related costs, which means all costs are customer- and/or capacity-related.

Q. HOW ARE COSTS CLASSIFIED BETWEEN CUSTOMER- AND CAPACITY-RELATED?

A. In WTGU's COSS, capital and operating costs are classified between customer- and capacity-related based on two primary classification factors. These primary classification factors determine the proportion of the cost of facilities (i.e., pipe and meters) required to serve customers irrespective of their average or peak use of the system and are classified as customer-related costs. The remaining portion of the cost of facilities is considered necessary to meet customer needs above the minimum required to serve them, and those costs are classified as capacity-related costs.

Q. PLEASE DESCRIBE HOW THE FIRST PRIMARY CLASSIFICATION FACTOR WAS DEVELOPED.

A. The first classification factor, referred to as "Pipe" in Schedule J-1, is developed on Schedule J-3. WTGU witness Matthew Smith identified the total number feet of pipe by diameter comprising the WTGU system from plant records. He then estimated the replacement cost per foot for each size of pipe. Using Mr. Smith's data, I calculated the total cost of replacing the pipe on the WTGU system to be approximately $729.9 million. I also calculated that the cost of replacing the pipe on the WTGU system with a minimum 2-inch pipe would be approximately $435.6

million. Dividing the $435.6 million cost of a 2-inch pipe system by the $729.9 million total replacement cost of WTGU's pipe indicates that 59.68% of pipe costs are customer-related, with the remaining 40.32% being capacity-related.

Q. IS THIS "PIPE" CLASSIFICATION CALCULATED ON SCHEDULE J-3 THE SAME AS IN GUD NO. 10235 AND DOCKET NO. OS-20-00004347?

A. In GUD No. 10235, the same 2-inch pipe was used as the minimum pipe size, but in Docket No. OS-20-00004347, I chose to use 1-inch pipe as the minimum size pipe explicitly to moderate cost shifts between customer classes. I now propose to return to the 2-inch minimum pipe size to calculate the "Pipe" classification factor, which has been approved as the standard minimum pipe size by the Commission for Atmos Energy and CenterPoint Energy.[1]

Q. PLEASE DESCRIBE HOW THE SECOND PRIMARY CLASSIFICATION FACTOR WAS DEVELOPED.

A. The second classification factor, referred to as "Meters" in Schedule J-1, is developed on Schedule J-4. WTGU witness Smith identified the total number of services by customer type and then estimated the cost to install a meter and riser for each. Using this data, I calculated the total cost of replacing all the meters and

[1] *E.g.*, *Statement of Intent of 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 Houston Division*, GUD No. 9902 consol., Final Order *Nunc Pro Tunc* at Finding of Fact No. 92 (May 4, 2010) ("The proposed minimum system study based on two-inch pipe is just and reasonable and consistent with precedent of the Railroad Commission"); *Petition for De Novo Review of the Denial of the Statement of Intent Filed by Atmos Energy Corp., Mid-Tex Division by the City of Dallas; Statement of Intent to Increase Gas Utility Rates in the Unincorporated Areas Served by the Mid-Tex Division*, GUD No. 9869 Interim Order at 2-3 (Jul. 14, 2009) (finding that the adoption of a minimum distribution system with two-inch pipe as methodology for cost allocation was reasonable, citing GUD Nos. 9672, 9670, and 9400).

risers on the WTGU system to be $11.6 million. I also calculated that the cost of replacing the meters and risers on the WTGU system at the cost of a basic residential meter and riser to be $8.2 million. Dividing the $8.2 million cost of a system with only basic residential meters by the $11.6 million total cost of the system with different sized meters and risers indicates that 71.02% of meter costs are customer-related, with the remaining 28.98% being capacity-related.

Q. WERE THESE PRIMARY CLASSIFICATION FACTORS USED TO DEVELOP ANOTHER CLASSIFICATION FACTOR?

A. Yes. As shown on page 3 of Schedule J-1, an "Aggregate" classification factor was developed using the data developed in Schedules J-3 and J-4. The Aggregate classification factor combines the pipe and meter costs of a minimum system and divides it by the total replacement cost of pipe and meters on the WTGU system. This Aggregate classification factor classifies 59.85% of costs as customer-related and the remaining 40.15% as capacity-related.

Q. WHAT WAS THE NEXT STEP IN THE COSS?

A. Having developed the Pipe, Meter, and Aggregate classification factors, the next step was to apply these factors to the three plant in service and accumulated depreciation categories (i.e., Joint, Jurisdictional, and Non-Jurisdictional) and O&M expense accounts as in the COSS in GUD No. 10235 and Docket No. OS-20-00004347. The accounts to which these three classification factors were applied can be identified by reference to the "Classification Factor" column in Schedule J-1. Based on the amounts classified as customer- and capacity-related in these accounts, eight additional classification factors were developed. These are shown on pages 3 and 4 of Schedule J-1.

Q. HOW WERE THESE OTHER CLASSIFICATION FACTORS USED?

A. The various other classification factors were then applied to the remaining rate base, O&M expense, A&G expense, taxes other than income, return on investment, and income taxes accounts to classify these capital and operating costs between customer- and capacity-related and to apportion them between Joint, Jurisdictional-Only, and Non-Jurisdictional-Only costs. The classification factor applied to each account is identified in the "Classification Factor" column in Schedule J-1.

Q. WHAT ARE THE RESULTS OF THE CLASSIFICATION OF COSTS IN THE COSS?

A Applying the applicable classification factor to each component of rate base (i.e., plant in service, accumulated depreciation, working capital items, non-investor supplied capital), operating expenses (i.e., O&M, A&G, and taxes other than income), capital costs (i.e., depreciation expense, return on investment, and net income taxes), and other income results in the Joint, Jurisdictional-Only, and Non-Jurisdictional-Only costs being classified between customer and capacity as follows, and which total Texas revenue requirements of $34,616,294 on Schedule A.

Costs	**Customer-Related**	**Capacity-Related**	**Total**
Joint	$ 12,106,686	$ 7,999,622	$ 20,106,308
Jurisdictional-Only	7,972,003	5,323,462	13,295,464
Non-Jurisdictional-Only	731,453	483,070	1,214,522
Total	**$ 20,810,141**	**$ 13,806,153**	**$ 34,616,294**

C. Cost Allocation

Q. HAVING CLASSIFIED COSTS BETWEEN CUSTOMER- AND CAPACITY-RELATED AND BETWEEN JOINT, JURISDICTIONAL-ONLY, AND NON-JURISDICTIONAL-ONLY, WHAT WAS THE NEXT STEP IN THE COSS?

A. Having identified and classified Joint, Jurisdictional-Only, and Non-Jurisdictional-Only costs, the next step in conducting WTGU's COSS was to allocate the respective customer- and capacity-related costs between WTGU's three customer classes: (1) Jurisdictional Domestic, (2) Jurisdictional Non-Domestic, and (3) Non-Jurisdictional. Initially, three primary allocation factors were developed: Customer Count, Design Day, and Throughput.

Q. WHAT ARE THE DIFFERENT CUSTOMERS ON THE WTGU SYSTEM?

A. WTGU's Texas customers are regarded as either "Jurisdictional," which means their rates are established in rate proceedings by either municipalities or the Commission, or "Non-Jurisdictional", where their rates are negotiated. As shown in the table below, there are four types of jurisdictional customers, which are grouped into two customer classes for rate purposes: (1) Domestic, which consists of residential customers, and (2) Non-Domestic, which consists of the three other types of customers. There are eight types of Non-Jurisdictional customers, which for ratemaking purposes, are treated as a single customer class.

Jurisdictional		**Non-Jurisdictional**	
Domestic	Non-Domestic	Public authority	Irrigation
Residential	Public authority	Interstate	Resale
	Small commercial	Small commercial	Transportation
	Large commercial	Large commercial	Gathering

Additional details on WTGU's customers are presented in Schedule K.

Q. PLEASE DESCRIBE THE CUSTOMER COUNT ALLOCATION FACTOR.

A. Customer Count is the number of customers in each customer class and is used to allocate some customer-related costs between customer classes. The Customer Count allocation factor was based on the average number of jurisdictional Domestic and Non-Domestic customers and Non-Jurisdictional customers during the test year. It was also used for billing units to calculate rates.

Q. WHAT IS THE DESIGN DAY ALLOCATION FACTOR?

A. The Design Day allocation factor is used to allocate some capacity-related costs between customer classes and is intended to reflect the portion of maximum demand that a customer class might place on the system. The Design Day allocation factor is developed on Schedule J-5. I used the same design day heating degree days ("HDDs") determined in GUD No. 10235 for WTGU's North, West, and South Zones, but applied them to adjusted 2023 test year peak month throughput (Schedules K-1 through K-3, respectively). The design days of the three zones were then combined to arrive at the Design Day allocation factor for each customer class. The Design Day allocation factor was also adjusted to include the average day demand of irrigation customers, as was done in WTGU's previous two rate cases.

Q. WHAT IS THE THROUGHPUT ALLOCATION FACTOR?

A. The Throughput allocation factor is used to allocate a limited number of customer- and capacity-related costs based on the relative volumes of gas used by each customer class. Except for customers that have heating-sensitive usage, which was normalized, the throughput allocation factor was based on test year volumes.

Q. PLEASE DESCRIBE HOW YOU NORMALIZED TEST YEAR THROUGHPUT FOR HEATING SENSITIVE CUSTOMERS.

A. Actual volumes during 2023 were weather normalized for Domestic, Public Authority, Small Commercial, and Large Commercial customers using the same methodology as in GUD No. 10235 and Docket No. OS-20-00004347, and as described in the Commission's *Natural Gas Rate Review Handbook*. Separate analyses were performed for customers in WTGU's North, West, and South Zones using different average HDDs for each zone. The weather normalization calculations are developed on Schedules K-4, K-5, and K-6 for the respective zones, with Schedules K-7, K-8, and K-9 containing unadjusted monthly data for each customer class and Schedules K-1, K-2, and K-3 presenting monthly weather adjusted volumes by customer class. The volume and customer count data contained in Schedules K-1 through K-9 is summarized for the test year on Schedule K, which also serves as the source of the billing units used to calculate rates for jurisdictional Domestic and Non-Domestic customers.

Q. IS THE USAGE OF ANY OTHER TYPE OF CUSTOMER AFFECTED BY WEATHER?

A. Yes. Rainfall affects the amount of gas used by irrigation customers. In GUD No. 10235, test year volumes for irrigation customers were normalized by using a four-year average. However, a review of usage by irrigation customers indicated that the average over the last four years was not appreciably different from test year usage. Because there is not a clearly better measure of representative usage, irrigation customers' test year volumes were used in developing the Throughput allocation factor in this case, as was done in Docket No. OS-20-00004347.

Q. WHAT WAS THE NEXT STEP IN THE COSS?

A. Having developed the Customer Count, Design Day, and Throughput data, the next step was to develop allocation factors applicable to the customer- and capacity-related costs of the Joint, Jurisdictional-Only, and Non-Jurisdictional-Only costs consistent with the COSS in GUD No. 10235 and Docket No. OS-20-00004347. When two allocation factors are identified (e.g., Customer/DD), the first is applied to customer-related costs and the second to capacity-related costs. Based on the amounts allocated to each of the three customer classes in these accounts, eight allocation factors were developed. These are shown on pages 3 and 4 of Schedule J-2. The allocation factor applied to each account is identified in the "Cost Allocation Factor" column in Schedule J-2.

Q. WOULD YOU PLEASE PROVIDE AN EXAMPLE OF HOW THE ALLOCATION OF CLASSIFIED COSTS WAS PERFORMED?

A. Yes. Consider Account No. 367 (Transmission Mains). WTGU has a total investment in transmission mains of $45.3 million, of which $36.6 million is Joint, $7.8 million is Jurisdictional-Only, and $0.9 million is Non-Jurisdictional-Only. For this account, both customer- and capacity-related costs are allocated using the Design Day factor, which is based on a Design Day for Domestic jurisdictional customers of 20,593 Mcf, 15,074 Mcf for Non-Domestic jurisdictional customers, and 105,970 Mcf for Non-Jurisdictional customers, or a total of 141,637 Mcf. Of the $36.6 million in Joint plant, Domestic jurisdictional customers are allocated 14.54% (20,593 Mcf divided by 141,637 Mcf), or $5.3 million. Non-Domestic jurisdictional customers are allocated 10.64% of the $36.6 million, or $3.9 million. The remaining 74.82%, or $27.4 million, is allocated to Non-Jurisdictional customers. Next, the $7.8 million in Jurisdictional-Only plant is allocated between just the Domestic and Non-Domestic jurisdictional classes. Domestic jurisdictional customers are allocated 57.75% (20,593 Mcf divided by 35,667 Mcf), or $4.5 million, and Non-Domestic jurisdictional customers are allocated the remaining 42.26% (15,074 Mcf divided by 35,667 Mcf) of the $7.8 million, or $3.3 million. Finally, the $0.9 million in Non-Jurisdictional-Only transmission mains is allocated 100% to Non-Jurisdictional customers, with none being allocated to Domestic or Non-Domestic jurisdictional customers. The end–result is that, of the $45.3 million in transmission mains, Domestic jurisdictional customers are allocated a total of $9.8 million ($5.3 million of Joint plant, plus $4.5 million of Jurisdictional-Only plant, plus zero of Non-jurisdictional plant). The Non-Domestic jurisdictional class is allocated $7.2 million ($3.9 million plus $3.3 million plus zero, respectively), and the Non-Jurisdictional class is allocated $28.3 million ($27.4 million plus zero plus $0.9 million).

Q. CAN YOU ALSO SHOW THIS ALLOCATION PROCESS IN TABLE FORM?

A. Yes. The allocation of the $43.5 million investment in Account 376 – Transmission Mains between customer classes described above is also summarized in the following table (dollars in millions):

Description	Joint	Jurisdictional Only	Non-Jurisdictional - Only	Total
Plant 376				
Trans. Mains	$ 36.6	$ 7.8	$ 0.9	$ 43.5
Design Day				
Domestic-Juris.	14.54%	57.75%	00.00%	20,593
Non-Dom.-Juris.	10.64%	42.26%	00.00%	15,074
Non-Juris.	74.82%	00.00%	100.00%	105,970
Allocated Costs				
Domestic-Juris.	$ 5.3	$ 4.5	--	$ 9.8
Non-Dom.-Juris.	$ 3.9	$ 3.3	--	$ 7.2
Non-Juris.	$ 27.4	--	$ 0.9	$ 28.3
Totals	**$ 36.6**	**$ 7.8**	**$ 0.9**	**$ 43.5**

A similar process to allocate the classified Joint, Jurisdictional-Only, and Non-Jurisdictional-Only costs to each of the three customer classes was applied for each component of rate base and revenue requirements, with the details being contained in Schedule J-2.

D. COSS Results

Q. WHAT ARE THE RESULTS OF THE COSS?

A. The customer- and capacity-related costs allocated to each of the three customer classes in the COSS are shown on page 3 of Schedule J-2, and are summarized and totaled in the following table:

	Jurisdictional		Non-Jurisdictional
Costs	**Domestic**	**Non-Domestic**	
Customer	$ 15,405,551	$ 2,470,463	$ 2,934,127
Capacity	$ 4,962,159	$ 3,627,958	$ 5,216,036
Total	**$ 20,367,710**	**$ 6,098,421**	**$ 8,150,163**

The sum of the total costs allocated to each of the three customer classes equals the Texas revenue requirements of $34,616,294 developed in the previous section.

Additionally, the amount of each component of revenue requirements allocated to each customer class in the COSS is shown on Schedule A.

Q. WHAT ARE COST-BASED RATES FOR JURISDICTIONAL CUSTOMERS BASED ON THE RESULTS OF THE COSS?

A. The customer- and capacity-related costs for Domestic and Non-Domestic jurisdictional customers shown above are converted to cost-based rates on Schedule A-1. For Domestic customers, the $15.4 million in customer-related costs are divided by the 17,924 average number of customers during the test year and 12 months, which produces a monthly customer charge of $71.63. Dividing the $5.0 million of capacity-related costs by adjusted test year volumes produces a consumption charge of $4.67 per Mcf. Similar calculations for Non-Domestic customers produce a monthly customer charge for this class of $82.89 and a consumption charge of $9.61 per Mcf.

Q. HOW DO THESE COST-BASED RATES COMPARE WITH CURRENT RATES?

A. Schedule A-2 and the following table compare WTGU's current rates, which include WTGU's pending requested GRIP charge, for Domestic and Non-Domestic customers with cost-based rates:

Description	Current Rates	Cost-Based Rates	Percentage Change
Domestic Customers			
Customer Charge	$ 23.42	$ 71.63	205.8%
Commodity Charge (Mcf)	$ 4.84	$ 4.67	-3.6%
Non-Domestic Customers			
Customer Charge	$ 43.57	$ 82.89	90.2%
Commodity Charge (Mcf)	$ 2.69	$ 9.61	257.4%

Q. IS WTGU REQUESTING THAT THE COMMISSION APPROVE THESE COST-BASED RATES?

A. No. Because of the overall magnitude of the increases required to charge cost-based rates and the distortions to the structure of existing rates, WTGU is requesting that the Commission approve rates for Domestic customers consisting of a $29.50 monthly customer charge and a $7.68 per Mcf consumption charge, and for Non-Domestic customers a monthly charge of $79.00 and a consumption charge of $4.89 per Mcf. These requested rates are compared to existing rates in the following table and on Schedule A-2:

Description	Current Rates	Requested Rates	Percentage Change
Domestic Customers			
Customer Charge	$ 23.42	$ 29.50	26.0%
Commodity Charge (Mcf)	$ 4.84	$ 7.68	58.7%
Non-Domestic Customers			
Customer Charge	$ 43.57	$ 79.00	81.3%
Commodity Charge (Mcf)	$ 2.69	$ 4.89	81.8%

As shown at the bottom of Schedule A, WTGU's requested rates represent an increase in revenues from Domestic customers of $4,327,298, or 42.5%, and from Non-Domestic customers of $2,451,592, or 81.6%.

IV. RATE OF RETURN

A. Introduction

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. The purpose of this section is to develop an overall rate of return to apply to WTGU's invested capital, or rate base, to be used to determine its cost of providing service and for interim rate adjustment, or GRIP, filings.

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),[2] 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.

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[2] *Bluefield Waterworks & Imp. Co. v. Pub. Serv. Comm'n of W. Va.,* 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923); *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944).

Q. IN GENERAL, HOW HAVE YOU GONE ABOUT DEVELOPING YOUR RECOMMENDED RATE OF RETURN FOR WTGU?

A. My evaluation begins with brief reviews of the operations and finances of WTGU, its parent WTG Downstream Holdings LLC ("WTG Downstream"), and general conditions in the capital markets, including a discussion of the actions the Federal Reserve Board ("Fed") is taking in response to the increases in the Consumer Price Index ("CPI"). With this background, I next develop a mix of investor-supplied capital (i.e., debt and equity) to be used as capital structure weightings to develop 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. I then evaluate my recommended ROE for WTGU for reasonableness and combine the capital cost components to calculate my recommended overall rate of return for WTGU.

B. Summary of Conclusions

Q. WHAT RATE OF RETURN ARE YOU RECOMMENDING FOR WTGU?

A. As developed on Exhibit BHF-1 attached hereto (and in Schedule E of WTGU's Rate Filing Schedules), I recommend an overall rate of return on WTGU's invested capital of 8.10%. This rate of return is based on capital structure ratios of 34.40% debt and 65.60% equity, a cost of debt of 3.06%, and an ROE of 10.75%.

Q. WHAT IS THE BASIS FOR THE CAPITAL STRUCTURE RATIOS USED TO CALCULATE WTGU'S RATE OF RETURN?

A. The capital structure ratios of 34.40% debt and 65.60% equity are those of WTGU's parent, WTG Downstream, at December 31, 2023. Although WTG Downstream's test year-end debt and equity ratios are lower and higher, respectively, than the capital structure ratios maintained by a proxy group of large, publicly traded local distribution companies ("LDCs") and those ratios approved by the Commission for the larger LDCs in Texas since 2016, they reflect how WTGU is actually financed and correspond to the greater risks of WTG Downstream's relatively smaller size.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED 3.06% COST OF DEBT?

A. Consistent with using WTG Downstream's actual capital structure ratios, I recommend that WTG Downstream's actual cost of debt be assigned to the debt component of its capital structure. At test year-end, the weighted average cost of WTG Downstream's debt was 3.06%, which compares with an average cost of debt for the proxy group of publicly traded LDCs of 4.14%.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED ROE OF 10.75%?

A. Based on applications of the DCF, CAPM, risk premium, and comparable earnings methods, I conclude that equity investors in WTGU require a rate of return for the use of their money in the range of 10.25% to 11.25%. For present purposes, I recommend an ROE for WTGU of 10.75%, which is the bottom of my range, be used to determine the cost of providing service and in GRIP filings.

Q. BRIEFLY DESCRIBE WTGU.

A. WTGU is headquartered in Midland, Texas, and operates a gas distribution system that consists of some 5,700 miles of pipe and currently serves approximately 23,500 customers in Texas and 4,600 in southwestern Oklahoma. Previously privately held by a single individual, since 2021 WTGU has been owned by WTG Downstream, which is ultimately owned 80% by Stonepeak Infrastructure Partners and 20% by the Estate of James Lee Davis and Family. At December 31, 2023, WTGU had approximately $225 million in total assets, with all of its financing being provided by WTG Downstream.

Q. BRIEFLY DESCRIBE WTG DOWNSTREAM.

A. WTG Downstream owns entities that are engaged in natural gas distribution (i.e., WTGU), gas transmission, and gas marketing. At December 31, 2023, WTG Downstream's assets totaled approximately $489 million, with revenues during 2023 totaling slightly more than $300 million. At year-end 2023, WTG Downstream's permanent financing consisted of $155 million of unrated, privately placed notes and approximately $291 million of equity.

Q. HOW DOES WTGU COMPARE IN SIZE WITH THE MAJOR LDCS IN TEXAS?

A. In the following table, WTGU is compared to the gas distribution operations of the three largest LDCs serving Texas – Atmos Energy Corporation ("Atmos"), CenterPoint Energy, Inc. ("CenterPoint"), and ONE Gas, Inc. ("ONE Gas") through its Texas Gas Service ("TGS") division. Besides their Texas operations, Atmos, CenterPoint, and ONE Gas also have substantial gas distribution activities in other states throughout the U.S., and Atmos and CenterPoint are also involved in other regulated and unregulated activities (dollar amounts in millions):

	Customers		Gas Distribution	
Company	**Texas**	**U.S.**	**Revenues**	**Net Plant**
Atmos	2,186,846	3,486,384	$ 4,097	$ 14,402
CenterPoint	1,908,946	4,313,954	$ 4,276	$ 11,455
ONE Gas	699,000	2,265,000	$ 2,371	$ 6,135
WTGU	23,538	28,125	$ 144	$ 204

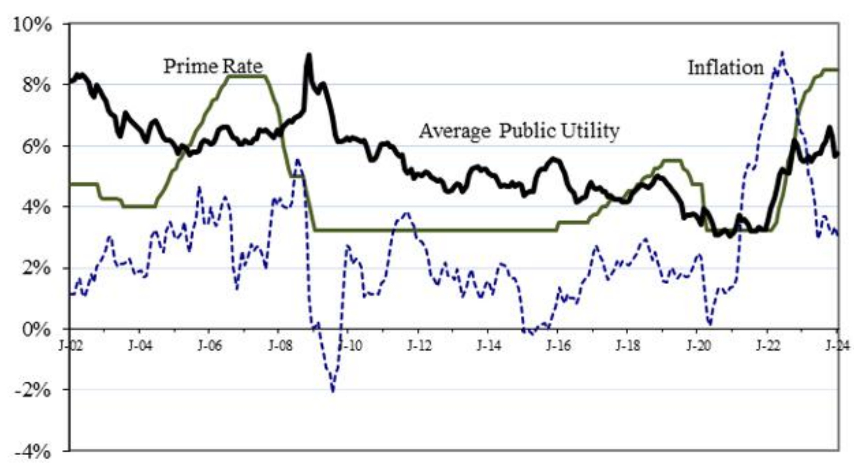
Q. WHAT ARE THE IMPLICATIONS OF THE ABOVE SIZE COMPARISON FOR DETERMINING WTGU'S RATE OF RETURN?

A. The significance of the above table is that WTGU is not in the same league as Atmos, CenterPoint, and TGS. Indeed, the three largest investor-owned utility ("IOU") LDCs in Texas are many multiples larger than WTGU, with its number of customers, revenues, and net plant being dwarfed by those of Atmos, CenterPoint, and TGS. This size difference affects various aspects of WTGU's operations and finances. As a small LDC having widely dispersed service areas and fewer financial resources, WTGU faces greater operating and financial risks than large LDCs in Texas and elsewhere. This fundamental fact is properly recognized and accounted-for in determining a fair rate of return for WTGU.

C. Capital Markets

Q. WHAT HAS BEEN THE PATTERN OF INTEREST RATES OVER THE LAST TWENTY YEARS?

A. Average long-term public utility bond rates, the borrowing prime rate, and inflation as measured by the CPI over the last approximately twenty years are plotted in the graph below. Beginning in 2002, the average yield on long-term public utility bonds generally fell because of monetary and fiscal policies designed to keep the economy growing. This decline ended abruptly with the 2008 financial market meltdown and global recession. Investors became exceedingly risk averse, causing interest rates on corporate bonds to spike, while government policies pushed down short-term interest rates and depressed economic conditions and lower energy prices reduced inflation. Over the next decade, various actions by the Fed to stimulate the economy through easy-money policies resulted in short- and long-term interest rates reaching record lows. These conditions were interrupted in early 2020 by the coronavirus pandemic and worldwide economic shutdown, although the impact on interest rates was moderated by extraordinary actions taken by the Fed in response. However, in late 2021 CPI inflation began to skyrocket, jumping from an average of around 2% over the prior 20 years to 7% in 2021, peaking at over 9% in June 2022, and since the third quarter of 2023 ranging between 3.0% and 3.5%:



Q. HOW HAS THE MARKET FOR COMMON EQUITY CAPITAL PERFORMED OVER THIS SAME PERIOD?

A. In the early 2000s, stock prices moved steadily higher as one of the longest bull markets in U.S. history continued unabated. In mid-2000, mounting concerns over prospects for future growth, particularly for firms in the high technology and telecommunications sectors, pushed equity prices lower, in some cases precipitously. Common stock prices generally recovered and reached record highs, buoyed in large part by widespread acquisition activity, until the capital market crisis and Great Recession occurred in 2008. Stock prices tumbled by some 40%, and while they recovered and reached all-time highs over the next decade, they crashed again in early 2020 due to the coronavirus pandemic. Since then, most stock indices reached all-time highs, but subsequently receded some 20% into bear market territory in response to inflation worries, soaring energy prices, and global events (e.g., the Russian invasion of Ukraine). They have recently fully recovered as inflation has abated and investors expect the Fed to discontinue hiking interest rates. Additionally, the stock market has become extraordinarily volatile, with share prices routinely changing more than full percentage points during a single day's trading. The graph below plots the performances of the Dow-Jones Industrial Average, the S&P 500, and the Dow Jones Utility Average since 2002 (the latter two indices were scaled for comparability):

Q. WHAT IS THE CURRENT OUTLOOK FOR THE U.S. ECONOMY?

A. The U.S. economy had fully recovered from the Great Recession when the coronavirus pandemic struck in early 2020, and the world economy came to a virtual stand-still. More than 30 million U.S. jobs were lost as a result of the pandemic, and unemployment reached almost 15%, not counting furloughed workers, throwing the U.S. into a recession overnight. To address the crisis, the U.S. Congress provided some $4.5 trillion in aid and stimulus spending, and the Fed held short-term interest rates near zero and purchased up to $120 billion a month in Treasury debt and mortgage-backed securities to suppress long-term interest rates. The combined effect of these fiscal and monetary policies, along with the population becoming vaccinated, is that U.S. economic activity subsequently increased to greater than prior to the coronavirus pandemic and unemployment fell to below 4%. As noted earlier, however, inflation began to increase markedly in 2021. After initially attributing the increase to supply-chain problems and then the Russian invasion of Ukraine, the Fed concluded that the dramatic rise in prices was not "transitory," and beginning in March 2022 it embarked on its most aggressive effort in more than two decades to curb inflation. This included increasing short-term interest rates, announcing that more hikes in the federal funds rate would follow, and reducing its $9 trillion inventory of Treasury debt and mortgage-backed securities up to $95 billion a month by not replacing maturing bonds. As inflation moderated in 2023, the Fed indicated that it might begin to reduce interest rates in 2024, but it has not done so because inflation has stubbornly remained above 3% and employment data continues to be strong. Whether the unprecedented actions during 2022-2023 by the Fed will reduce inflation to its target level of 2% is yet unknown. Thus far, they have been only partially successful, with the ultimate outcome remaining a significant uncertainty hanging over all segments of the U.S. economy.

Q. HOW DO THESE UNCERTAINTIES AFFECT THE COST OF CAPITAL?

A. Hikes in the federal funds rate by the Fed and significant reductions in its long-term bond inventory are intended to increase the cost of all borrowing, including by LDCs. As will be explained more later, higher interest rates also increase the cost of more risky equity capital. This, coupled with the greater volatility in stock prices that also increases the risk of investing in common equities, supports the conclusion that the relatively low capital cost environment that has existed for the last decade has ended. As a result, the cost of both debt and equity is expected to remain higher for the foreseeable future, and the ROEs authorized for LDCs over the last few years, including those allowed by this Commission, must be adjusted to recognize the changes in capital markets. Only an ROE that reflects the current capital market conditions faced by LDC's will fairly compensate a utility's investors, enable LDCs to attract new capital on reasonable terms, and maintain their financial integrity.

V. CAPITAL STRUCTURE AND COST OF DEBT

A. Capital Structure

Q. WHAT ROLE DOES CAPITAL STRUCTURE PLAY IN DEVELOPING A UTILITY'S RATE OF RETURN?

A. A utility's capital structure reflects the mix of permanent 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 permanent capital are typically used to weight the cost of debt, cost of preferred stock, and ROE in calculating an overall rate of return.

Q. WHAT SOURCES OF CAPITAL ARE USED TO FINANCE WTGU'S INVESTMENT IN UTILITY ASSETS?

A. As noted earlier, WTGU relies entirely on capital supplied by WTG Downstream to finance its investment in assets. In the following table, WTG Downstream's December 31, 2023 balance sheet reflects that it is financed with approximately $152.7 million of debt and $291.1 million of common equity. Also developed there are WTG Downstream's test year-end capital structure ratios of 34.40% debt and 65.60% equity:

Capital Component	Amount	% of Total
Long-term Debt	$ 152,670,914	34.40%
Common Equity	291,132,606	65.60%
Total	**$ 443,803,520**	**100.00%**

Q. HOW ARE LDCS TYPICALLY FINANCED?

A. Based on data published by the American Gas Association, the gas distribution industry had the following composite capital structure ratios between 2018 and 2022:

Capital Component	2022	2021	2020	2019	2018
Long-term Debt	42.8%	43.6%	42.3%	41.0%	41.9%
Preferred Stock	0.0%	0.0%	0.0%	0.9%	0.1%
Common Equity	57.2%	56.4%	57.7%	58.1%	58.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

The table above indicates that LDCs as a whole have historically financed their investment in utility plant with around 42% long-term debt and 58% preferred and common equity. Alternatively, Exhibit BHF-2 displays the capital structure ratios at fiscal year-ends 2020 through 2023 for an industry group of publicly traded LDCs. Beginning with the nine companies included in *The Value Line Investment Survey's* ("*Value Line*") Natural Gas Utility industry, I excluded Southwest Gas Holdings, which is in the midst of a restructuring, and UGI Corp., which is not predominantly engaged in natural gas distribution. This resulted in an industry group consisting of: 1) Atmos Energy, 2) Chesapeake Utilities, 3) New Jersey Resources, 4) NiSource, Inc., 5) Northwest Natural Gas, 6) ONE Gas, and 7) Spire, Inc. While the average debt and equity ratios for this group of publicly traded LDCs are approximately 50%, the upper end of the equity ratio range for the group is 60% or above.

Q. WHAT CAPITAL STRUCTURE RATIOS HAS THE COMMISSION APPROVED FOR MAJOR LDCS IN TEXAS?

A. The following table lists the capital structure ratios approved by the Commission for the three largest LDCs in Texas from 2016 through the present. As shown there, with but a few exceptions, the equity ratios included in the rates of return authorized by the Commission have been approximately 60%:

Date	Docket	Utility	Debt	Equity
05/03/2016	10488	TGS – Gulf Coast	39.80%	60.20%
09/27/2016	10506	TGS – West Texas	39.90%	60.10%
11/15/2016	10526	TGS –Central Texas	39.50%	60.50%
05/23/2017	10567	CP Energy– Houston	44.85%	55.15%
12/05/2017	10640	Atmos – Dallas	41.49%	58.51%
03/20/2018	10656	TGS – RGV	38.71%	61.29%
05/22/2018	10669	CP Energy – S. Texas	45.00%	55.00%
11/13/2018	10739	TGS – NTSA	37.84%	62.16%
12/11/2018	10742	Atmos – Mid-Tex	39.82%	60.18%
12/11/2018	10743	Atmos – West Texas	39.82%	60.18%
02/05/2019	10766	TGS – BSSA	37.84%	62.16%
05/21/2019	10779	Atmos – Mid-Tex	39.82%	60.18%
04/21/2020	10900	Atmos – West Texas	39.88%	60.12%
05/21/2019	10920	CP Energy-Beaumont/ETx	43.05%	56.95%
08/04/2020	10928	TGS – CGSA	41.00%	59.00%
01/18/2023	00009896	TGS – WNSA	40.26%	59.74%
01/30/2024	00014399	TGS – RGV	40.93%	59.07%
6/25/2024	00015513	CenterPoint Energy	39.39%	60.61%

Q. WHAT CAPITAL STRUCTURE RATIOS DO YOU RECOMMEND BE USED TO CALCULATE WTGU'S RATE OF RETURN?

A. Although WTG Downstream's capital structure ratios at December 31, 2023 of 34.40% debt and 65.60% equity are lower and higher, respectively, than industry averages and the approximately 40% debt and 60% equity the Commission has previously allowed the three major LDCs in Texas, they are consistent with the considerably smaller size of WTGU and the greater operating risks it faces because of its dispersed operations throughout West Texas, and that the only collateral for WTG Downstream's debt is its assets and those of subsidiaries. Accordingly, I recommend that WTG Downstream's actual, test year-end capital structure ratios of 34.40% debt and 65.60% equity be used to calculate WTGU's rate of return.

B. Cost of Debt

Q. PLEASE DESCRIBE WTG DOWNSTREAM'S DEBT.

A. WTG Downstream's debt is a privately placed Note Agreement consisting of three series of senior notes. Series A is a $55,000,000 note bearing an interest rate of 2.36% maturing in 2026. Series B is also a $55,000,000 note, but carries an interest rate of 2.72% and matures in 2028. Series C is a $45,000,000 note having an interest rate of 2.99% that matures in 2031. Interest is payable semi-annually and the notes are secured only by the assets of WTG Downstream and its subsidiaries. At December 31, 2023, there remained unamortized debt issuance expenses of $2,329,086 on the notes.

Q. WHAT IS THE AVERAGE COST OF WTG DOWNSTREAM'S DEBT?

A. As shown below and on Exhibit BHF-3, the weighted average cost of WTG Downstream's debt at December 31, 2023 is 3.06%:

Description	Amount	Interest Rate	Annual Expense
Series A	$ 55,000,000	2.36%	$ 1,298,000
Series A	55,000,000	2.72%	1,496,000
Series A	45,000,000	2.99%	1,345,000
Debt Issuance Costs	(2,329,086)		538,746
Total	**$152,670,914**		**$4,678,246**
Cost of Debt		**3.06 %**	

Q. HOW DOES WTG DOWNSTREAM'S 3.06% AVERAGE COST OF DEBT COMPARE TO THAT OF OTHER LDCS?

A. As shown in the lower portion of Exhibit BHF-3, the average cost of debt for the seven large, publicly traded LDC proxy group described earlier is 4.14%, considerably greater than WTG Downstream's cost of 3.06%.

Q. WHAT COST OF DEBT DO YOU RECOMMEND BE USED TO CALCULATE WTGU'S RATE OF RETURN?

A. Consistent with using WTG Downstream's actual capital structure ratios, I recommend that WTG Downstream's test year-end average cost of debt of 3.06% be used to calculate WTGU's rate of return.

VI. RETURN ON EQUITY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section is to develop a cost of equity range for WTGU as the basis for selecting the ROE I recommend be used to determine its cost of providing service and in GRIP filings. 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 a group of publicly traded LDCs to estimate their costs of equity, which is then adjusted to reflect WTGU's smaller size and greater risk. Next, the CAPM is described and alternative cost of equity estimates for WTGU are developed using this method. WTGU's cost of equity is also estimated using the risk premium method based on authorized ROEs, and a comparable earnings method is applied. The results of these analyses are then combined to arrive at a cost of equity range for WTGU, from which my recommended ROE is selected.

A. Cost of Equity Concept

Q. HOW IS 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. Because all assets compete with each other for investors' funds, riskier assets must yield a higher expected rate of return than less risky assets in order for investors to be willing to hold them.

Given this risk-return tradeoff, the minimum required rate of return (k) from an asset (i) can be generally expressed as:

$$k_i = R_f + RPi$$

where: R_f = Risk-free rate of return; and
RP_I = Risk premium required to hold more risky asset i.

Thus, the minimum required rate of return for a particular asset at any point in time is a function of: 1) the yield on risk-free assets, and 2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff can be readily documented in certain segments of the capital markets where required rates of return can be directly inferred from market data and generally accepted measures of risk exist. For example, bond yields are reflective of investors' expected rates of return, and bond ratings are indicative of the risk of fixed income securities. The observed yields on government securities and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

To illustrate, average yields during May 2024 on 30-year U.S. Treasury bonds, investment grade public utility bonds of different ratings reported by Moody's Investors Service, and below investment grade double-B corporate bonds derived from data reported by the St. Louis Federal Reserve Bank are shown in the following table. As evidenced there, as risk increases (measured by progressively lower bond ratings), the required rate of return (measured by yields) rises accordingly. Also shown are the indicated risk premiums over long-term government securities for the additional risk associated with each bond rating category:

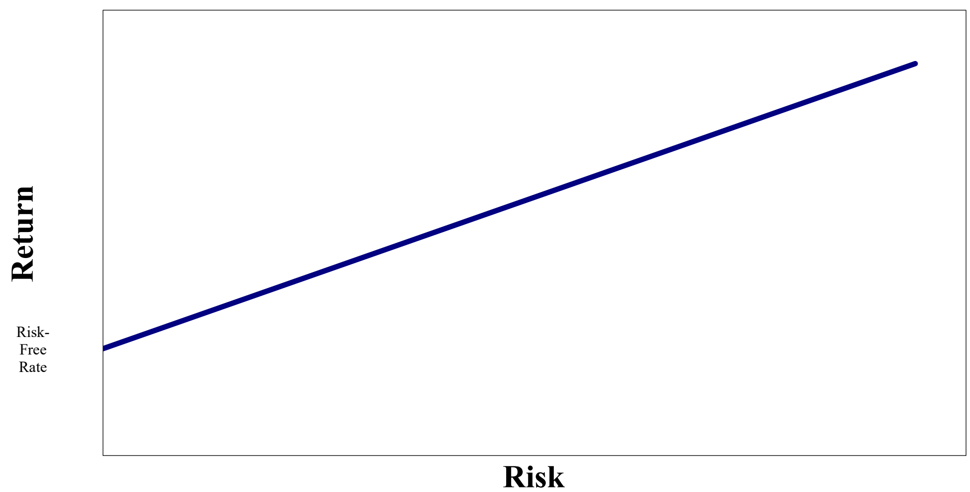
Bond and Rating	May 2024 Yield	Risk Premium Over 30-Year Treasury
U.S. Treasury		
30-Year	4.62%	--
Public Utility		
Aa	5.62%	1.00%
A	5.74%	1.12%
Baa	5.97%	1.35%
Corporate		
BB	**6.42%**	**1.80%**

Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. Documenting the risk-return tradeoff for assets other than fixed income securities is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets (e.g., common stock), required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether to hold common stocks and other assets, just as when choosing among fixed income securities. Accordingly, it is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets.

The extension of the risk-return tradeoff from assets with observable required rates of return (e.g., bonds) to other assets is represented by the concept of a "capital market line." In particular, competition between securities and among investors in the capital markets drives the prices of assets to equilibrium such that the expected rate of return from each is commensurate with its risk. Thus, the expected rate of return from any asset is a risk-free rate of return plus a corresponding risk premium. This concept of a capital market line is illustrated below. The vertical axis represents required rates of return and the horizontal axis indicates relative riskiness, with the intercept of the capital market line being the risk-free rate of return.

Capital Market Line



Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY FOR A UTILITY?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the utility specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, by extrapolating interest rates, or through an analysis of other financial data.

Q. DO YOU RELY ON A SINGLE METHOD TO ESTIMATE THE COST OF EQUITY FOR WTGU?

A. No. Despite the theoretical appeal of or precedent for using a particular method to estimate the cost of equity, no single approach can be regarded as wholly reliable. Therefore, I use multiple methods to estimate the cost of equity. Indeed, it is essential that estimates of investors' minimum required rate of return produced by one method be compared with those produced by other methods, and that all cost of equity estimates be required to pass fundamental tests of reasonableness and economic logic.

B. Discounted Cash Flow Model

Q. HOW ARE DCF MODELS USED TO ESTIMATE THE COST OF EQUITY?

A. The use of DCF models to estimate the cost of equity is essentially an attempt to replicate the market valuation process 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. IS THERE ANYTHING ELSE THAT AFFECTS THE USE OF THE DCF MODEL TO ESTIMATE INVESTORS' REQUIRED RATE OF RETURN?

A. Yes. When the DCF model came into widespread use as a method to estimate the cost of equity in the 1960s and 1970s, it was regarded as a fair representation of investor behavior and share valuation. Investors bought and sold stocks based on their fundamental underlying value, which was tied to long-term dividend and stock price growth expectations. That is no longer the case. It is estimated that some 75% of equities bought and sold on the New York Stock Exchange are now "high frequency" or "algorithmic" trades. These trades are not investors buying stocks for the long-term, but are short-term, computer-initiated trades intended to take advantage of market discrepancies, movements, and information. Accordingly, it is not clear whether common stock prices are now based on the valuation assumed by DCF theory and upon which estimating the cost of equity using the DCF model is predicated.

Q. THESE CAVEATS NOTWITHSTANDING, HOW DID YOU ESTIMATE THE COST OF EQUITY USING THE DCF MODEL?

A. Because WTGU has no publicly traded common stock, the DCF model cannot be used to estimate its cost of equity directly. For this reason, and to avoid measurement error associated with applying the DCF model to a single firm, I applied the constant growth form of the DCF model to the proxy group of nine publicly traded LDCs identified earlier. As described earlier, I began with the nine companies included in *Value Line's* Natural Gas Utility industry at May 24, 2024, and then excluded UGI Corp. because it is not predominantly engaged in natural gas distribution and Southwest Gas Holdings because it is in the midst of a major restructuring. This resulted in a proxy group consisting of the seven LDCs listed on Exhibit BHF-4.

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 LDC PROXY GROUP?

A. Because estimating the cost of equity using the DCF model is an attempt to replicate how investors arrived at an observed stock price, all of its components should be contemporaneous. Price, dividend, and growth data from different points in time, or averaged over long time periods, violate the matching principle underlying the DCF model. Therefore, dividend yield was calculated by dividing an estimate of dividends to be paid by each of the LDCs in the group over the next twelve months, obtained from the index to *Value Line's* May 31, 2024 edition, by the average closing price of each firm's stock during the month of May 2024. The expected dividends, representative price, and resulting dividend yield for each of the seven LDCs are displayed on Exhibit BHF-4. As calculated there, the average dividend yield for the industry group is 3.90%. Also shown is the median for the group of 3.88%, which removes the impact of extreme low and high values on the average.

Q. EXPLAIN HOW ESTIMATES OF INVESTORS' LONG-TERM GROWTH EXPECTATIONS ARE CUSTOMARILY DEVELOPED FOR USE IN THE CONSTANT GROWTH DCF MODEL.

A. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an effort to replicate the mechanism investors used to arrive at observable stock prices. Therefore, the only "g" that matters in using the DCF model to estimate the cost of equity is that which investors expect and have embodied in current market prices.

Q. WHAT DRIVES INVESTORS' GROWTH EXPECTATIONS?

A. Trends in earnings, which ultimately support future dividends and share price, play a pivotal role in determining investors' long-term growth expectations. Security analysts' growth forecasts are generally regarded as the closest single measure of the expected long-term growth rate of the constant growth DCF model. While being primarily based on the outlook for a firm, they also reflect the utility's historical experience and other factors considered by investors in forming their long-term growth expectations. Moreover, various empirical studies have found that security analysts' projections are a superior source of DCF growth rates. The 5-year earnings growth projections by security analysts for each of the seven gas utilities reported by *Value Line*, LSEG's Institutional Brokers Estimate System ("I/B/E/S"), and Zacks Investment Research ("Zacks") are displayed on Exhibit BHF-5, with the averages for the group being 6.1%, 7.2%, and 5.8%, respectively. Again, to eliminate the impact of extreme values, the medians for the group are also shown, which range between 5.5% and 7.4%. Also shown on Exhibit BHF-5 are the 10-year and 5-year historical earnings growth rates reported by *Value Line* for each of the seven gas utilities, which average 4.8% and 6.9%, respectively, and have medians of 5.0% and 6.0%, respectively.

Q. HOW ELSE ARE INVESTOR EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS FOR A FIRM OFTEN ESTIMATED FOR USE IN THE CONSTANT GROWTH DCF MODEL?

A. In DCF theory and practice, growth in book equity comes from the reinvestment of earnings within the business and the effects of external financing. Accordingly, conventional applications of the constant growth DCF model often examine the relationships between variables that determine the "sustainable" growth attributable to these two factors.

Q. HOW IS A FIRM'S SUSTAINABLE GROWTH ESTIMATED?

A. The sustainable growth rate is calculated by the formula:

$$g = br + sv$$

where "b" is the expected earnings retention ratio (one minus the dividend payout ratio), "r" is the expected rate of return earned on book equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion ratio. The "br" term represents the growth from reinvesting earnings within the firm while the "sv" term represents the growth from external financing. This external financing growth results because existing shareholders share in a portion of any excess received from selling new shares at a price above book value.

Q. WHAT GROWTH RATE DOES THE SUSTAINABLE GROWTH METHOD SUGGEST FOR THE GAS UTILITY GROUP?

A. The sustainable growth rate for each of the gas utilities in the industry group based on *Value Line's* projections for 2027-2029 is developed in Exhibit BHF-6. As shown there, the sustainable growth method implies an average long-term growth rate for the LDC utility group of 5.7%, and 6.0% based on the median.

Q. WHAT ARE OTHER PROJECTED AND HISTORICAL GROWTH RATES FOR THE INDUSTRY GROUP?

A. Exhibit 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 seven gas utilities in the industry group. The averages for the LDC group range from a negative 2.8% (5-year historical price growth) to 8.7%

(projected price growth), with the medians ranging from a negative 2.3% to 9.2%. Besides the fact that some of these growth rates, when combined with the group's approximately 3.90% dividend yield, imply implausible cost of equity estimates, the variation in these other growth rates results in their providing only limited guidance as to the prospective growth that investors expect.

Q. WHAT IS YOUR CONCLUSION AS TO THE LONG-TERM GROWTH THAT INVESTORS ARE EXPECTING FROM THE INDUSTRY GROUP?

A. After excluding clearly unreliable indicators of growth, the plausible growth rates shown on Exhibits BHF-5, BHF-6, and BHF-7 indicate a range for the LDC group of between approximately 5.50% and 6.75%. Taken together, I conclude that investors expect long-term growth from the LDC group in the 5.5% to 6.5% range.

Q. WHAT CURRENT DCF COST OF EQUITY ESTIMATES DO THESE GROWTH RATE RANGES IMPLY FOR THE GAS UTILITY GROUP?

A. Summing the LDC group's average dividend yield of approximately 3.90% with a 5.50% to 6.50% growth rate range indicates a current DCF cost of equity for the industry group of between 9.4% and 10.4%.

Q. IS THIS DCF COST OF EQUITY RANGE DIRECTLY APPLICABLE TO WTGU?

A. No. The 9.4% to 10.4% DCF cost of equity range developed above is for the group of seven LDCs with publicly traded common stock that, as shown on Exhibit BHF-9, have average Standard & Poor's and Moody's bond ratings, which is generally regarded as the most comprehensive indicator of a firm's risk, of BBB+

and single-A, respectively. As noted earlier, WTG Downstream is not rated by the major bond rating agencies, and, if it were, would likely be rated below investment grade or, at best, a low triple-B, which means that it is a more risky investment than the LDC group. Similarly, as will be discussed more completely in the next section on the CAPM, it is well accepted in the financial literature that investors require a higher return from smaller firms than from larger firms, all other things equal. As also shown on Exhibit BHF-9, the average market capitalization ("market cap") of the firms in the LDC proxy group is some $6.6 billion. While neither WTGU nor WTG Downstream have a market cap *per se* because they are not publicly traded, one can be estimated based on WTG Downstream's $291 million test year-end book equity shown earlier. Specifically, multiplying this book equity times the average market-to-book ratio of the firms in the proxy group of 1.51 times shown in Exhibit BHF-9 implies a market cap of approximately $440 million. This market cap is only about one-fifteenth of the $6.6 billion average of the proxy group. Accordingly, to make the LDC industry DCF cost of equity range applicable to WTGU, an adjustment is necessary to account for its greater risk and smaller size relative to the firms in the LDC group.

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT NECESSARY TO ACCOUNT FOR THE GREATER RISK AND SMALLER SIZE OF WTGU VERSUS THE LDC INDUSTRY GROUP?

A. Determining the additional return investors require for investing in the common stock of an unrated, smaller utility versus a less risky single-A/triple-B rated, larger utility is complicated by the fact that the cost of equity is unobservable. However, the minimum premium shareholders require for bearing the additional operating and financial risks of a small LDC having only a few dispersed service areas and limited resources versus a multi-state diversified LDC can be gauged by looking at the differences, or spreads, between the yields on below investment grade bonds versus single-A and triple-B rated utility bonds. As shown earlier, the average yield on corporate bonds rated BB in May 2024 was 6.42% versus the yields on single-A and triple-B utility bonds of 5.74% and 5.97%, respectively. Assuming WTG Downstream were a double-B credit, the yield on BB bonds implies that the cost of equity to WTGU for its greater operating and financial risks is between at least 45 and 68 basis points (i.e., 6.42% minus 5.97% and 6.42% minus 5.74%, respectively) higher than for the publicly traded LDC proxy group.

Meanwhile, Kroll publishes annually a schedule of rate of return premiums to account for differences in the market capitalization of a firm's equity relative to the S&P 500. In the far right columns of the table in the upper portion of Exhibit BHF-9, the market cap of each LDC in the proxy group is displayed along with its corresponding size premium, with the average size premium for the proxy group being 0.93%. From the schedule of size premiums at the bottom of Exhibit BHF-9, the size premium for a firm with a market cap of $440 million is 1.99%. This implies that the return premium necessary to account for WTG Downstream's smaller size relative to the LDC group is 1.06% (i.e., 1.99% minus the LDCs' 0.93%).

Q. WHAT COST OF EQUITY FOR WTGU IS IMPLIED BY YOUR DCF ANALYSIS?

A. Although the 45 to 68 basis point premium for risk differences and the 1.06% premium for size differences may be theoretically additive, for present purposes, I have adjusted the DCF cost of equity range for the LDC group by 0.75% to account for both factors. Adding the 0.75% adjustment for WTGU's smaller size and greater risk to the 9.40% to 10.40% DCF cost of equity range for the LDC industry group produces a DCF cost of equity range for WTGU of 10.15% to 11.15%.

C. Capital Asset Pricing Model

Q. HOW ELSE DID YOU ESTIMATE THE COST OF EQUITY?

A. The cost of equity to WTGU was also estimated using the CAPM, which is a theory of market equilibrium that serves as the basis for current financial education and management. Under the CAPM, investors are assumed fully diversified, so that the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole, which is measured using a "beta" coefficient. Beta reflects the tendency of a stock's price to follow changes in the market, with stocks having a beta less than 1.00 being considered less risky and stocks with a beta greater than 1.00 being regarded as more risky. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j \, (R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free interest rate;
R_m = expected return on the market portfolio; and
β_j = beta, or systematic risk, for stock j.

While the CAPM is not without controversy, it is routinely referenced in the financial literature and regulatory proceedings, and firms' beta values are widely reported.

Q. HOW DID YOU APPLY THE CAPM?

A. I applied the CAPM using two methods to determine the risk premium for the market as a whole, or the (R_m - R_f) term in the CAPM formula. The first was based on historical rates of return and the second was based on forward-looking estimates of investors' required rates of return. In both instances, the companies included in the S&P 500 index were used as a proxy for the market portfolio and the 30-year U.S. Treasury bond served as the risk-free investment.

Q. PLEASE DESCRIBE THE FIRST METHOD BASED ON HISTORICAL RATES OF RETURN.

A. Under the historical rate of return approach, equity risk premiums are calculated by first measuring the rate of return (including dividends and capital gains and losses) actually realized on an investment in common stocks over historical time periods. The historical return on bonds is then subtracted from that earned on common stocks to measure equity risk premiums. Widely used in academia, the historical rate of return approach is based on the assumption that, given a sufficiently large number of observations over long historical periods, average market rates of return will converge to investors' required rates of return. From a more practical perspective, investors may base their expectations for the future on, or may have come to expect that they will earn, rates of return corresponding to those in the past.

Q. WHAT IS THE MARKET RISK PREMIUM BASED ON HISTORICAL RATES OF RETURN?

A. Perhaps the most exhaustive study of historical rates of return, and the one most frequently cited in regulatory proceedings, is that contained in *Market Results for Stocks, Bonds, Bills and Inflation*, variously published by Ibbotson Associates, Morningstar, Duff & Phelps, and Kroll. The annual rate of return realized on the S&P 500 averaged 12.04% over the period 1926 through 2023 while the annual average income rate of return on 30-year Treasury bonds over this same period averaged 4.87%. Thus, the market risk premium based on historical average annual rates of return is 7.17%, as shown on Exhibit BHF-8.

Q. PLEASE DESCRIBE THE SECOND METHOD BASED ON FORWARD-LOOKING REQUIRED RATES OF RETURN.

A. Consistent with the CAPM being an expectational (i.e., forward-looking) model, the second method estimated the market risk premium using current indicators of investors' required rates of return. This method is similar to how the market risk premium is calculated under the *Federal Energy Regulatory Commission's May 21, 2020 Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines* ("FERC Policy Statement"). For the market portfolio, the cost of equity was estimated by applying the DCF model to the firms in the S&P 500 paying cash dividends, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. The expected dividend yield for each firm was obtained from *Value Line,* with the expected growth rate being based on the earnings forecasts published for each firm by *Value Line*, I/B/E/S, and Zacks.

As shown in footnote (b) on Exhibit BHF-8, summing the 1.72% expected dividend yield for this market group, which is composed primarily of non-regulated firms, with the average of the *Value Line*, I/B/E/S, and Zacks projected growth rates of 10.05% produces a required rate of return from the market portfolio (R_m) of 11.77%.

Q. WHAT IS THE MARKET RISK PREMIUM BASED ON FORWARD-LOOKING REQUIRED RATES OF RETURN?

A. From the 11.77% required rate of return on the market portfolio, a market risk premium is calculated by subtracting the average yield on 30-year Treasury bonds during May 2024 of 4.62%. This produces a forward-looking market risk premium of 7.15%.

Q. WHAT IS THE NEXT STEP IN APPLYING THE CAPM?

A. Having calculated market risk premiums of 7.16% and 7.15% using historical rates of return and forward-looking rates of return, respectively, the next step is to calculate specific risk premiums for the LDC industry. This is done by multiplying the alternative market risk premium estimates by the LDC group's average beta of 0.88, calculated using firm betas obtained from *Value Line* and shown on Exhibit BHF-8, which produces LDC industry risk premiums of 6.30% and 6.28%.

Q. WHAT ARE THE RESULTING THEORETICAL CAPM COST OF EQUITY ESTIMATES FOR THE LDC INDUSTRY?

A. As shown on Exhibit BHF-8, summing the industry risk premiums of 6.30% and 6.28% with a risk-free interest rate equal to the May 2024 30-year Treasury bond yield of 4.62% produces current theoretical CAPM cost of equity estimates for LDCs of 10.92% and 10.90%.

Q. ARE THESE THEORETICAL CAPM COST OF EQUITY ESTIMATES ACCURATE MEASURES OF INVESTORS' REQUIRED RATE OF RETURN FROM WTGU?

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 WTGU ONCE SIZE EFFECTS ARE TAKEN INTO ACCOUNT?

A. As discussed earlier, the premium for firms having a market capitalization of $440 million is 1.99%, which means that the theoretical CAPM cost of equity estimates need to be increased by 1.99% to account for WTG Downstream smaller size relative to the S&P 500. As shown on Exhibit BHF-8, increasing the theoretical CAPM cost of equity estimates by this size premium results in current CAPM cost of equity estimates for WTGU based on historical rates of return and forward-looking rates of return of 12.91% and 12.89%, respectively.

D. Risk Premium Method

Q. HOW ELSE DID YOU ESTIMATE THE COST OF EQUITY?

A. I also estimated the cost of equity to WTGU using a risk premium method based on ROEs previously authorized for LDCs by state regulatory commissions. The risk premium method to estimate investors' required rate of return is an extension of the risk-return tradeoff observed with bonds to common stocks. The cost of equity is estimated by determining the additional return investors require to forego the relative safety of a bond and bear the greater risks associated with common stock, and then adding this equity risk premium to the current yield on bonds.

Q. GENERALLY, DESCRIBE THE APPLICATION OF THE RISK PREMIUM METHOD USING AUTHORIZED ROES.

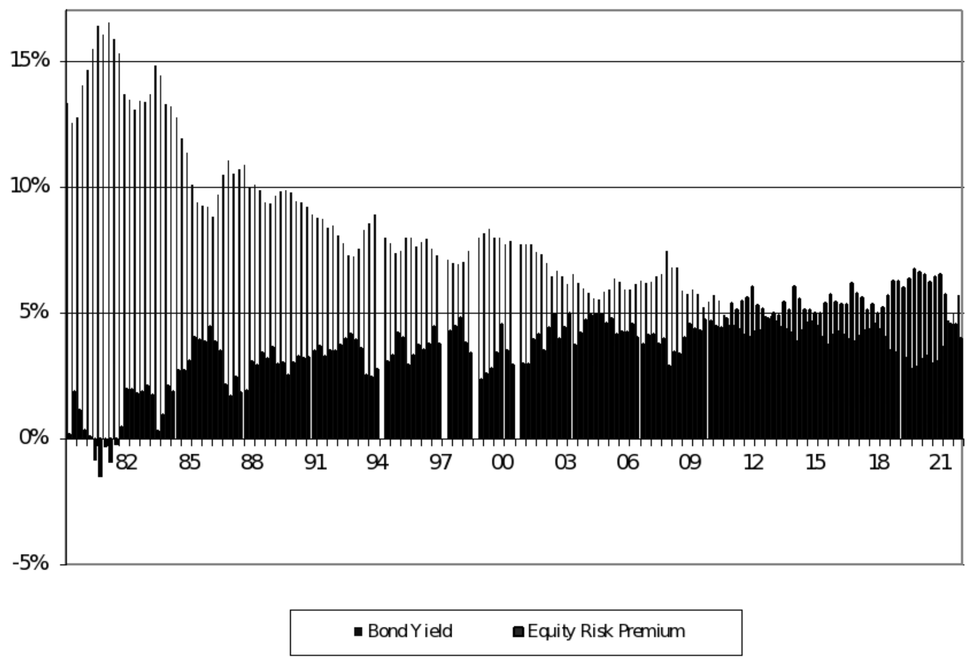
A. Application of the risk premium method based on authorized ROEs is predicated on the presumption that allowed returns reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final orders. A current risk premium is estimated based on the difference between past authorized ROEs and then-prevailing interest rates. This risk premium is then added to current interest rates to estimate the cost of equity. The strength of this approach is that it is based on decades of data reflecting regulatory commissions' evaluation of ROEs for LDCs under various capital market conditions. Because this risk premium method is LDC-specific, it produces cost of equity estimates judged necessary to compensate for the risks of gas distribution and the ROE required to enable an LDC to attract capital on reasonable terms under current capital market conditions.

Q. WHAT WAS THE PRINCIPAL SOURCE OF THE DATA USED TO APPLY THIS RISK PREMIUM METHOD?

A. Regulatory Research Associates, Inc., ("RRA"), which is now a group within S&P Global Market Intelligence, and its predecessors have compiled the ROEs authorized for major electric and gas utilities by regulatory commissions across the U.S. The average ROE authorized for natural gas utilities published by RRA in each quarter between 1980 and 2024 are displayed in Exhibit BHF-10. As shown there, the ROEs granted to LDCs over this approximately 44-year period have averaged 11.36%, while the average utility bond yield has averaged 7.55%, resulting in an average risk premium of 3.81%.

Q. IS THIS 3.81% AVERAGE RISK PREMIUM THE RELEVANT BENCHMARK FOR ESTIMATING THE COST OF EQUITY?

A. No. It is necessary to account for the fact that authorized ROEs do not move in lockstep with interest rates. In particular, when interest rate levels are relatively high, ROEs tend to be lower (i.e., equity risk premiums narrow), and when interest rates are relatively low, authorized ROEs are greater (i.e., equity risk premiums increase). This inverse relationship can be observed in the data contained in Exhibit 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 ACCOUNT FOR THE RELATIONSHIP BETWEEN EQUITY RISK PREMIUMS AND INTEREST RATES?

A. To account for the fact that equity risk premiums are lower when interest rates are high and higher when interest rates are low, I developed two regression equations relating authorized past equity risk premiums to average utility bond yields. The first was a simple linear regression between equity risk premiums and interest rates and the second equation adjusted for first order autocorrelation using the Prais-Winsten algorithm. Shown in the bottom portion of Exhibit BHF-10, substituting the May 2024 yield of 5.78% on average utility bonds into the regression equations indicates that the equity risk premium at current interest rate levels is between approximately 4.63% and 4.74%

Q. WHAT COST OF EQUITY DOES THIS RISK PREMIUM IMPLY FOR WTGU?

A. As discussed earlier, WTG Downstream does not have a credit rating by rating agencies, but if it did, WTG Downstream would likely be rated double-B or, at best, a low triple-B credit. Therefore, I added the 4.63% and 4.74% equity risk premiums developed on Exhibit BHF-10 to the May 2024 yield on triple-B rated utility bonds of 5.97% to calculate a risk premium cost of equity range for WTGU of between 10.60% and 10.71%. Using a double-B interest rate of 6.42%, the risk premium cost of equity for WTGU is between 11.05% and 11.16%.

E. Comparable Earnings Method

Q. WHAT IS THE LAST METHOD THAT YOU USED TO ESTIMATE THE COST OF EQUITY?

A. Often referred to as the comparable earnings method, this approach looks to the rates of return that other firms of comparable risk and that compete for investors' capital are expected to earn on their book equity. Reference to the expected return on book equity of other LDCs demonstrates the level of earnings that is needed 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. Exhibit BHF-11 displays the return on book equity projected for each of the seven LDCs in the industry group for the 2024, 2025, and the 2027-2029 timeframes, calculated by dividing *Value Line's* projected earnings per share by average book value per share. As shown there, the average expected book ROE for the group is

8.90% in 2024, 9.20% for 2025, and 9.90% for 2027-2029, with medians of 8.4%, 8.4%, and 9.9%, respectively. Again, adjusting these industry numbers upwards by 75 basis points to reflect the smaller size and greater risk of WTGU relative to the proxy group results in comparable earnings values of between 9.15% and 10.65%.

F. Rate of Return on Equity Range

Q. WHAT IS YOUR CONCLUSION AS TO THE CURRENT COST OF EQUITY RANGE FOR WTGU?

A. The DCF method indicates a cost of equity range for WTGU of between approximately 10.15% and 11.15%, while the CAPM indicates a cost of equity range of approximately 12.9%. Meanwhile, the risk premium method based on the authorized ROEs for LDCs and applicable interest rates indicates a cost of equity of between approximately 10.6% and 11.2%, and the comparable earnings method implies a fair rate of return on book equity of between approximately 9.2% and 10.7%. Taken together, my analyses indicate that investors currently require a ROE from WTGU in the range of 10.75% to 11.75%.

Q. WHAT ROE DO YOUR RECOMMEND BE USED TO CALCULATE WTGU'S RATE OF RETURN?

A. Although my quantitative analyses indicate a cost of equity to WTGU in the range of 10.75% to 11.75%, as discussed earlier, WTGU is not requesting an increase to cost-based rates. For purposes of determining the cost of providing service and in GRIP filings, I recommend that an ROE from the bottom of my range, or 10.75%, be used.

Q. HAVE YOU CONDUCTED ANY CHECKS OF REASONABLENESS OF YOUR RECOMMENDED ROE FOR WTGU?

A. Yes. The reasonableness of my recommended 10.75% ROE for WTGU can be evaluated by reviewing the ROEs previously granted by the Commission. The table below lists the ROEs authorized for the three largest LDCs in Texas from 2016 through the present:

Date	Docket	Utility	ROEs
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%
4/21/2020	10900	Atmos-West Texas	9.80%
4/21/2020	10920	CP Entex-	9.65%
8/4/2020	10928	TGS-CGSA	9.50%
1/18/2023	00009896	TGS-WNSA	9.60%
1/30/2024	00014399	TGS-RGVSA	9.70%
6/25/2024	00015513	CenterPoint Energy	9.80%

Since 2016, the ROEs authorized Atmos, CenterPoint, and TGS have ranged between 9.5% and 10.1%. However, this historical range must be adjusted upwards to account for current interest rates on utility bonds being approximately 5.8% versus an average of 4.2% over the 2016-2023 timeframe, and for WTGU's greater risk and smaller size relative to Atmos, CenterPoint, and TGS. Once these adjustments are made, WTGU's requested 10.75% ROE is fully supported by the Commission's past ROE decisions.

VII. OVERALL RATE OF RETURN

Q. WHAT OVERALL RATE OF RETURN DO YOU RECOMMEND BE USED TO DETERMINE WTGU'S COST OF PROVIDING SERVICE AND IN GRIP FILINGS?

A. I recommend an overall rate of return for present purposes of 8.10%. As developed in Exhibit BHF-1 (and in Schedule E of WTGU's Rate Filing Schedules), this rate of return is the result of combining capital structure ratios of 34.40% debt and 65.60% equity with a cost of debt of 3.06% and an ROE of 10.75%.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes, it does.

APPENDIX A

BRUCE H. FAIRCHILD

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

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Austin, Texas 78751
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Summary of Qualifications

M.B.A. and Ph.D. in finance, accounting, and economics; Certified Public Accountant. Extensive consulting experience involving regulated industries, valuation of closely-held businesses, and other economic analyses. Previously held managerial and technical positions in government, academia, and business, and taught at the undergraduate, graduate, and executive education levels. Broad experience in technical research, computer modeling, and expert witness testimony.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included revenue requirements, rate of return, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Other assignments have involved some seventy valuations as well as various economic (e.g., damage) analyses, typically in connection with litigation. Presented expert witness testimony before courts and regulatory agencies on over one hundred occasions.
Adjunct Assistant Professor, University of Texas at Austin (Sep. 1979 to May. 1981)	Taught undergraduate courses in finance: Fin. 370 – Integrative Finance and Fin. 357 – Managerial Finance.
Assistant Director, Economic Research Division, Public Utility Commission of Texas (Sep. 1976 to Aug. 1979)	Division consisted of approximately twenty-five financial analysts, economists, and systems analysts responsible for rate of return, rate design, special projects, and computer systems. Directed Staff participation in rate cases, presented testimony on approximately thirty-five occasions, and was involved in some forty other cases ultimately settled. Instrumental in the initial development of rate of return and financial policy for newly-created agency. Performed independent research and managed State and Federal funded projects. Assisted in preparing appeals to the Texas Supreme Court and testimony presented before the Interstate Commerce Commission and Department of Energy. Maintained communications with financial community, industry representatives, media, and consumer groups. Appointed by Commissioners as Acting Director.

Assistant Professor, College of Business Administration,
University of Colorado at Boulder
(Jan. 1977 to Dec. 1978)

Taught graduate and undergraduate courses in finance: Fin. 305 – Introductory Finance, Fin. 401 – Managerial Finance, Fin. 402 – Case Problems in Finance, and Fin. 602 – Graduate Corporate Finance.

Teaching Assistant,
University of Texas at Austin
(Jan. 1973 to Dec. 1976)

Taught undergraduate courses in finance and accounting: Acc. 311 – Financial Accounting, Acc. 312 – Managerial Accounting, and Fin. 357 – Managerial Finance. Elected to College of Business Administration Teaching Assistants' Committee.

Internal Auditor,
Sears, Roebuck and Company, Dallas, Texas
(Nov. 1970 to Aug 1972)

Performed audits on internal operations involving cash, accounts receivable, merchandise, accounting, and operational controls, purchasing, payroll, etc. Developed operating and administrative policy and instruction. Performed special assignments on inventory irregularities and Justice Department Civil Investigative Demands.

Accounts Payable Clerk,
Transcontinental Gas Pipeline Corp., Houston, Texas
(May. 1969 to Aug. 1969)

Processed documentation and authorized payments to suppliers and creditors.

Education

Ph.D., Finance, Accounting, and Economics,
University of Texas at Austin
(Sep. 1974 to May 1980)

Doctoral program included coursework in corporate finance, investment theory, accounting, and economics. Elected to honor society of Phi Kappa Phi. Received University outstanding doctoral dissertation award.

Dissertation: *Estimating the Cost of Equity to Texas Public Utility Companies*

M.B.A., Finance and Accounting,
University of Texas at Austin,
(Sep. 1972 to Aug. 1974)

Awarded Wright Patman Scholarship by World and Texas Credit Union Leagues.

Professional Report: *Planning a Small Business Enterprise in Austin, Texas*

B.B.A., Accounting and Finance,
Southern Methodist University, Dallas, Texas
(Sep. 1967 to Dec. 1971)

Dean's List 1967-1971 and member of Phi Gamma Delta Fraternity.

Other Professional Activities

Certified Public Accountant, Texas Certificate No. 13,710 (October 1974); entire exam passed in May 1972. Member of the American Institute of Certified Public Accountants (Honorary).

Participated as session chairman, moderator, and paper discussant at annual meetings of Financial Management Association, Southwestern Finance Association, American Finance Association, and other professional associations.

Visiting lecturer in Executive M.B.A program at the University of Stellenbosch Graduate Business School, Belleville, South Africa (1983 and 1984).

Associate Editor of *Austin Financial Digest*, 1974-1975. Wrote and edited a series of investment and economic articles published in a local investment advisory service.

Military

Texas Army National Guard, Feb. 1970 to Sep. 1976. Specialist 5th Class with duty assignments including recovery vehicle operator for armor unit and company clerk for finance unit.

Bibliography

Monographs

"On the Use of Security Analysts' Growth Projections in the DCF Model," with William E. Avera, *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds., Institute for Study of Regulation (1982).

"An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies", with William E. Avera, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982).

"The Spring Thing (A) and (B)" and "Teaching Notes", with Mike E. Miles, a two-part case study in the evaluation, management, and control of risk; distributed by *Harvard's Intercollegiate Case Clearing House*; reprinted in *Strategy and Policy: Concepts and Cases*, A. A. Strickland and A. J. Thompson, Business Publications, Inc. (1978) and *Cases in Managing Financial Resources*, I. Matur and D. Loy, Reston Publishing Co., Inc. (1984).

"Energy Conservation in Existing Residences, Project Director for development of instruction manual and workshops promoting retrofitting of existing homes, *Governor's Office of Energy Resources* and *Department of Energy* (1977-1978).

"Linear Algebra," "Calculus," "Sets and Functions," and "Simulation Techniques," contributed to and edited four mathematics programmed learning texts for MBA students, *Texas Bureau of Business Research* (1975).

Articles and Notes

"How to Value Personal Service Practices," with Keith Wm. Fairchild, *The Practical Accountant* (August 1989).

"The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test," with Adrien M. McKenzie, *Public Utilities Fortnightly* (May 25, 1989).

"North Arctic Industries, Limited," with Keith Wm. Fairchild, *Case Research Journal* (Spring 1988).

"Regulatory Effects on Electric Utilities' Cost of Capital Reexamined," with Louis E. Buck, Jr., *Public Utilities Fortnightly* (September 2, 1982).

"Capital Needs for Electric Utility Companies in Texas: 1976-1985", *Texas Business Review* (January-February 1979), reprinted in "The Energy Picture: Problems and Prospects", J. E. Pluta, ed., *Bureau of Business Research* (1980).

"Some Thoughts on the Rate of Return to Public Utility Companies," with William E. Avera, *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978).

"Regulatory Problems of EFTS," with Robert McLeod, *Issues in Bank Regulation* (Summer 1978) reprinted in *Illinois Banker* (January 1979).

"Regulation of EFTS as a Public Utility," with Robert McLeod, *Proceedings of the Conference on Bank Structure and Competition* (1978).

"Equity Management of REA Cooperatives," with Jerry Thomas, *Proceedings of the Southwestern Finance Association* (1978).

"Capital Costs Within a Firm," *Proceedings of the Southwestern Finance Association* (1977).

"The Cost of Capital to a Wholly-Owned Public Utility Subsidiary," *Proceedings of the Southwestern Finance Association* (1977).

Selected Papers and Presentations

"Federal Energy Regulatory Commission Audits of Common Carriers (Procedures for Audit Compliance)", Energy Transfer Accounting Employee Education, Dallas and Houston, Texas (December 2018).

"Perspectives on Texas Utility Regulation", TSCPA 2016 Energy Conference, Austin, Texas (May 16, 2016).

"Legislative Changes Affecting Texas Utilities," Texas Committee of Utility and Railroad Tax Representatives, Fall Meeting, Austin, Texas (September 1995).

"Rate of Return," "Origins of Information," Economics," and "Deferred Taxes and ITC's," New Mexico State University and National Association of Regulatory Utility Commissioners Public Utility Conferences on Regulation and the Rate-Making Process, Albuquerque, New Mexico (October 1983, 1984, 1985, 1986, 1987, 1988, 1990, 1991, 1992, 1994, and 1995, and September 1989); Pittsburgh, Pennsylvania (April 1993); and Baltimore, Maryland (May 1994 and 1995).

"Developing a Cost-of-Service Study," 1994 Texas Section American Water Works Association Annual Conference, Amarillo, Texas (March 1994).

"Financial Aspects of Cost of Capital and Common Cost Considerations," Kidder, Peabody & Co. Two-Day Rate Case Workshop for Regulated Utility Companies, New York, New York (June 1993).

"Cost-of-Service Studies and Rate Design," General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

"Rate Base and Revenue Requirements," The University of Texas Regulatory Institute Fundamentals of Utility Regulation, Austin, Texas (June 1989 and 1990).

"Determining the Cost of Capital in Today's Diversified Companies," New Mexico State University Public Utilities Course Part II, Advanced Analysis of Pricing and Utility Revenues, San Francisco, California (June 1990).

"Estimating the Cost of Equity," Oklahoma Association of Tax Representatives, Tulsa, Oklahoma (May 1990).

"Impact of Regulations," Business and the Economy, Leadership Dallas, Dallas, Texas (November 1989).

"Accounting and Finance Workshop" and "Divisional Cost of Capital," New Mexico State University Current Issues Challenging the Regulatory Process, Albuquerque, New Mexico (April 1985 and 1986) and Santa Fe, New Mexico (March 1989).

"Divisional Cost of Equity by Risk Comparability and DCF Analyses," NARUC Advanced Regulatory Studies Program, Williamsburg, Virginia (February 1988) and USTA Rate of Return Task Force, Chicago, Illinois (June 1988).

"Revenue Requirements," Revenue, Pricing, and Regulation in Texas Water Utilities, Texas Water Utilities Conference, Austin, Texas (August 1987 and May 1988).

"Rate Filing – Basic Ratemaking," Texas Gas Association Accounting Workshop, Austin, Texas (March 1988).

"The Effects of Regulation on Fair Market Value: P.H. Robinson – A Case Study," Annual Meeting of the Texas Committee of Utility and Railroad Tax Representatives, Austin, Texas (September 1987).

"How to Value Closely-held Businesses," TSCPA 1987 Entrepreneurs Conference, San Antonio, Texas (May 1987).

"Revenue Requirements" and "Determining the Rate of Return", New Mexico State University Regulation and the Rate-Making Process, Southwestern Water Utilities Conference, Albuquerque, New Mexico (July 1986) and El Paso, Texas (November 1980).

"How to Evaluate Personal Service Practices," TSCPA CPE Exposition 1985, Houston and Dallas, Texas (December 1985).

"How to Start a Small Business – Accounting and Record Keeping," University of Texas Management Development Program, Austin, Texas (October 1984).

"Project Financing of Public Utility Facilities", TSCPA Conference on Public Utilities Accounting and Ratemaking, San Antonio, Texas (April 1984).

"Valuation of Closely-Held Businesses," Concho Valley Estate Planning Council, San Angelo, Texas (September 1982).

"Rating Regulatory Performance and Its Impact on the Cost of Capital," New Mexico State University Seminar on Regulation and the Cost of Capital, El Paso, Texas (May 1982).

"Effect of Inflation on Rate of Return," Cost of Capital Conference and Workshop, Pinehurst, North Carolina (April 1981).

"Original Cost Versus Current Cost Regulation: A Re-examination," Financial Management Association, New Orleans, Louisiana (October 1980).

"Capital Investment Analysis for Electric Utilities," The University of Texas at Dallas, Richardson, Texas (June 1980).

"The Determinants of Capital Costs to the Electric Utility Industry," with Cedric E. Grice, Southwestern Finance Association, San Antonio, Texas (March 1980).

"The Entrepreneur and Management: A Case Study," Small Business Administration Seminar, Austin, Texas (October 1979).

"Capital Budgeting by Public Utilities: A New Perspective," with W. Clifford Atherton, Jr., Financial Management Association, Boston, Massachusetts (October 1979).

"Issues in Regulated Industries – Electric Utilities," University of Texas at Dallas 4th Annual Public Utilities Conference, Dallas, Texas (July 1979).

"Investment Conditions and Strategies in Today's Markets," American Society of Women Accountants, Austin, Texas (January 1979).

"Attrition: A Practical Problem in Determining a Fair Return to Public Utility Companies," Financial Management Association, Minneapolis, Minnesota (October 1978).

"The Cost of Equity to Wholly-Owned Electric Utility Subsidiaries," with William L. Beedles, Financial Management Association, Minneapolis, Minnesota (October 1978).

"PUC Retrofitting Program," Texas Electric Cooperatives Spring Workshop, Austin, Texas (May 1978).

"The Economics of Regulated Industries," Consumer Economics Forum, Houston, Texas (November 1977).

"Public Utilities as Consumer Targets – Is the Pressure Justified?" University of Texas at Dallas 2nd Annual Public Utilities Conference, Dallas, Texas (July 1977).

APPENDIX B

BRUCE H. FAIRCHILD
SUMMARY OF TESTIMONY BEFORE REGULATORY AGENCIES

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
1.	Arkansas Electric Cooperative	Arkansas PSC	U-3071	Aug-80	Wholesale Rate Design
2.	East Central Oklahoma Electric Cooperative	Oklahoma CC	26925	Sep-80	Retail Rate Design
3.	Kansas Gas & Electric Company	Kansas CC	115379-U	Nov-80	PURPA Rate Design Standards
4.	Kansas Gas & Electric Company	Kansas CC	128139-U	May-81	Attrition
5.	City of Austin Electric Department	City of Austin	--	Jun-81	PURPA Rate Design Standards
6.	Tarrant County Water Control and Improvement District No. 1	Texas Water Commission	--	Oct-81	Wholesale Rate Design
7.	Owentown Gas Company	Texas RRC	2720	Jan-82	Revenue Requirements and Retail Rate Design
8.	Kansas Gas & Electric Company	Kansas CC	134792-U	Aug-82	Attrition
9.	Mississippi Power Company	Mississippi PSC	U-4190	Sep-82	Working Capital
10.	Lone Star Gas Company	Texas RRC	3757; 3794	Feb-83	Rate of Return on Equity
11.	Kansas Gas & Electric Company	Kansas CC	134792-U	Feb-83	Rate of Return on Equity
12.	Southwestern Bell Telephone Company	Oklahoma CC	28002	Oct-83	Rate of Return on Equity
13.	Morgas Company	Texas RRC	4063	Nov-83	Revenue Requirements
14.	Seagull Energy	Texas RRC	4541	Jul-84	Rate of Return
15.	Southwestern Bell Telephone Company	FCC	84-800	Nov-84	Rate of Return on Equity
16.	Kansas Gas & Electric Company, Kansas City Power & Light Company, and Kansas Electric Power Cooperatives	Kansas CC	142098-U; 142099-U; 142100-U	May-85	Nuclear Plant Capital Costs and Allowance for Funds Used During Construction
17.	Lone Star Gas Company	Texas RRC	5207	Oct-85	Overhead Cost Allocation
18.	Westar Transmission Company	Texas RRC	5787	Nov-85 Jan-86 Jul-86	Rate of Return, Rate Design, and Gas Processing Plant Economics
19.	City of Houston	Texas Water Commission	RC-022; RC-023	Nov-86	Line Losses and Known and Measurable Changes
20.	ENSTAR Natural Company	Alaska PUC	TA 50-4; R-87-2; U-87-2	Nov-86 May-87 May-87	Cost Allocation, Rate Design, and Tax Rate Changes
21.	Brazos River Authority	Texas Water Commission	RC-020	Jan-87	Revenue Requirements and Rate Design
22.	East Texas Industrial Gas Company	Texas RRC	5878	Feb-87	Revenue Requirements and Rate Design

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies
(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
23.	Seagull Energy	Texas RRC	6629	Jun-87	Revenue Requirements
24.	ENSTAR Natural Company	Alaska PUC	U-87-42	Jul-87 Sep-87 Sep-87	Cost Allocation, Rate Design, and Contracts
25.	High Plains Natural Gas Company	Texas RRC	6779	Sep-87	Rate of Return
26.	Hughes Texas Petroleum	Texas RRC	2-91,855	Jan-88	Interim Rates
27.	Cavallo Pipeline Company	Texas RRC	7086	Sep-88	Revenue Requirements
28.	Union Gas System, Inc.	Kansas CC	165591-U	Mar-89 Aug-89	Rate of Return
29.	ENSTAR Natural Gas Company	Alaska PUC	U-88-70	Mar-89	Cost Allocation and Bypass
30.	Morgas Co.	Texas RRC	7538	Aug-89	Rate of Return and Cost Allocation
31.	Corpus Christi Transmission Company	Texas RRC	7346	Sep-89	Revenue Requirements
32.	Amoco Gas Co.	Texas RRC	7550	Oct-89	Rate of Return and Cost Allocation
33.	Iowa Southern Utilities	Iowa Utilities Board	RPU-89-7	Nov-89 Mar-90	Rate of Return on Equity
34.	Southwestern Bell Telephone Company	FCC	89-624	Feb-90 Apr-90	Rate of Return on Equity
35.	Lower Colorado River Authority	Texas PUC	9427	Mar-90 Aug-90 Aug-90	Revenue Requirements
36.	Rio Grande Valley Gas Company	Texas RRC	7604	May-90	Consolidated FIT and Depreciation
37.	Southern Union Gas Company	El Paso PURB	--	Oct-90	Disallowed Expenses and FIT
38.	Iowa Southern Utilities	Iowa Utilities Board	RPU-90-8	Nov-90 Feb-91	Rate of Return on Equity
39.	East Texas Gas Systems	Texas RRC	7863	Dec-90	Revenue Requirements
40.	San Jacinto Gas Transmission	Texas RRC	7865	Dec-90	Revenue Requirements
41.	Southern Union Gas Company	Austin; Texas RRC	-- 7878	Feb-91 Feb-91	Rate of Return and Acquisition Adjustment
42.	Southern Union Gas Company	Port Arthur; Texas RRC	-- 8033	Mar-91 Aug-91 Oct-91	Rate of Return and Acquisition Adjustment
43.	Cavallo Pipeline Company	Texas RRC	8016	Jun-91	Revenue Requirements

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
44.	New Orleans Public Service Inc.	New Orleans City Council	CD-91-1	Jun-91 Mar-92	Rate of Return on Equity
45.	Houston Pipe Line Company	Texas RRC	8017	Jul-91	Rate of Return
46.	Southern Union Gas Company	El Paso PURB	--	Aug-91 Sep-91	Acquisition Adjustment
47.	Southwestern Gas Pipeline, Inc.	Texas RRC	8040	Jan-92 Feb-92	Rate Design and Settlement
48.	City of Fort Worth	Texas Water Commission	8748-A 9261-A	Mar-92 Aug-92 Dec-92 Oct-94 Nov-94	Interim Rates, Revenue Requirements, and Public Interest
49.	Southern Union Gas Company	Oklahoma Corp. Com.	--	Jun-92	Rate of Return
50.	Minnegasco	Minnesota PUC	G-008/GR-92-400	Jul-92 Dec-92	Rate of Return
51.	Guadalupe-Blanco River Authority	Texas PUC	11266	Sep-92	Cost Allocation and Bond Funds
52.	Dorchester Intra-State Gas System	Texas RRC	8111	Oct-92 Nov-92	Rate Impact of System Upgrade
53.	Corpus Christi Transmission Company GP and GPII	Texas RRC	8300 8301	Oct-92 Oct-92	Revenue Requirements
54.	East Texas Industrial Gas Company	Texas RRC	8326	Mar-93	Revenue Requirements
55.	Arkansas Louisiana Gas Company	Arkansas PSC	93-081-U	Apr-93 Oct-93	Rate of Return on Equity
56.	Texas Utilities Electric Company	Texas PUC	11735	Jun-93 Jul-93	Impact of Nuclear Plant Construction Delay
57.	Minnegasco	Minnesota PUC	G-008/GR-93-1090	Nov-93 Apr-94	Rate of Return
58.	Gulf States Utilities Company	Municipalities	--	May-94 Oct-94 Nov-94	Rate of Return on Equity
59.	Louisiana Power & Light Company	Louisiana PSC	U-20925	Aug-94 Feb-95	Rate of Return on Equity
60.	San Jacinto Gas Transmission	Texas RRC	8429	Sep-94	Revenue Requirements
61.	Cavallo Pipeline Company	Texas RRC	8465	Sep-94	Revenue Requirements
62.	Eastrans Limited Partnership	Texas RRC	8385	Oct-94	Revenue Requirements
63.	Gulf States Utilities Company	Louisiana PSC	U-19904	Oct-94	Rate of Return on Equity

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Summary of Testimony Before Regulatory Agencies

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
64.	Entergy Services, Inc.	FERC	ER95-112-000	Mar-95 Nov-95	Rate of Return on Equity
65.	East Texas Gas Systems	Texas RRC	8435	Apr-95	Revenue Requirements
66.	System Energy Resources, Inc.	FERC	ER95-1042-000	May-95 Dec-95 Jan-96	Rate of Return on Equity
67.	Minnegasco	Minnesota PUC	G-008/GR-95-700	Aug-95 Dec-95	Rate of Return
68.	Entex	Louisiana PSC	U-21586	Aug-95	Rate of Return
69.	City of Fort Worth	Texas NRCC	SOAH 582-95-1084	Nov-95	Public Interest of Contract
70.	Seagull Energy Corporation	Texas RRC	8589	Nov-95	Revenue Requirements
71.	Corpus Christi Transmission Company LP	Texas RRC	8449	Feb-96	Revenue Requirements
72.	Missouri Gas Energy	Missouri PSC	GR-96-285	Apr-96 Sep-96 Oct-96	Rate of Return
73.	Entex	Mississippi PSC	96-UA-202	May-96	Rate of Return
74.	Entergy Gulf States, Inc.	Louisiana PSC	U-22084	May-96	Rate of Return on Equity (Gas)
75.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-96 Oct-96	Rate of Return on Equity
76.	American Gas Storage, L.P.	Texas RRC	8591	Sep-96	Revenue Requirements
77.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	Sep-96 Oct-96	Rate of Return on Equity
78.	Lone Star Pipeline and Gas Company	Texas RRC	8664	Oct-96 Jan-97	Rate of Return
79.	Entergy Arkansas, Inc.	Arkansas PSC	96-360-U	Oct-96 Sep-97	Rate of Return on Equity
80.	East Texas Gas Systems	Texas RRC	8658	Nov-96	Revenue Requirements
81.	Entergy Gulf States, Inc.	Texas PUC	16705	Nov-96 Jul-97	Rate of Return on Equity
82.	Eastrans Limited Partnership	Texas RRC	8657	Nov-96	Revenue Requirements
83.	Enserch Processing, Inc.	Texas RRC	8763	Nov-96	Interim Rates
84.	Entergy New Orleans, Inc.	City of New Orleans	UD-97-1	Feb-97 Mar-97 May-98	Rate of Return on Equity

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Summary of Testimony Before Regulatory Agencies

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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
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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
110	ENSTAR Natural Gas Company	Alaska PUC	U-00-88	Jun-01 Aug-01 Nov-01 Sep-02 Dec-02	Revenue Requirements, Cost Allocation, and Rate Design
111.	TXU Gas Distribution	Texas RRC	9225	Jul-01	Rate of Return
112.	Centana Intrastate Pipeline LLC	Texas RRC	9243	Aug-01	Rate of Return
113.	Maxwell Water Supply Corp.	Texas NRCC	SOAH-582-01-0802	Oct-01 Mar-02 Apr-02	Reasonableness of Rates
114.	Reliant Energy Arkla	Arkansas PSC	01-243-U	Dec-01 Jun-01	Rate of Return
115.	Entergy Services, Inc.	FERC	ER01-2214-000	Mar-02	Rate of Return on Equity
116.	TXU Lone Star Pipeline	Texas RRC	9292	Apr-02	Rate of Return
117.	Southern Union Gas Company	El Paso PURB	--	Apr-02	Rate of Return
118.	San Jacinto Gas Transmission Co.	Texas RRC	9301	May-02	Rate of Return
119.	Duke Energy Intrastate Network	Texas RRC	9302	May-02	Rate of Return
120.	Reliant Energy Arkla	Oklahoma CC	200200166	May-02	Rate of Return
121.	TXU Gas Distribution	Texas RRC	9313	Jul-02 Sep-02	Rate of Return
122.	Entergy Mississippi, Inc.	Mississippi PSC	2002-UN-256	Aug-02	Rate of Return on Equity
123.	Aquila Storage & Transportation LP	Texas RRC	9323	Sep-02	Revenue Requirements
124.	Panther Pipeline Ltd.	Texas RRC	9291	Oct-02	Revenue Requirements
125.	SEMCO Energy	Michigan PSC	U-13575	Nov-02	Revenue Requirements
126.	CenterPoint Energy Entex	Louisiana PSC	U-26720	Jan-03	Rate of Return
127.	Crosstex CCNG Transmission Ltd.	Texas RRC	9363	May-03	Revenue Requirements
128.	TXU Gas Company	Texas RRC	9400	May-03 Jan-04	Rate of Return
129.	Eastrans Limited Partnership	Texas RRC	9386	May-03	Rate of Return
130.	CenterPoint Energy Entex	City of Houston		Jun-03	Rate of Return
131.	East Texas Gas Systems, L.P.	Texas RRC	9385	Jun-03	Rate of Return
132.	ENSTAR Natural Gas Company	Alaska RCA	U-03-084	Aug-03 Nov-03	Line Extension Surcharge
133.	CenterPoint Energy Arkla	Louisiana PSC		Nov-03	Rate of Return
134.	ENSTAR Natural Gas Company	Alaska RCA	U-03-091	Feb-04	Cost Separation and Taxes

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Summary of Testimony Before Regulatory Agencies

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
135.	Sid Richardson Pipeline, Ltd.	Texas RRC	9532	Jun-04 Nov-04	Revenue Requirements
136.	ETC Katy Pipeline, Ltd.	Texas RRC	9524	Sep-04	Revenue Requirements
137.	CenterPoint Energy Entex	Mississippi PSC	03-UN-0831	Sep-04	Rate Formula
138.	Centana Intrastate Pipeline LLC	Texas RRC	9527	Sep-04	Rate of Return
139.	SEMCO Energy	Michigan PSC	U-14338	Dec-04	Revenue Requirements
140.	Atmos Energy – Energas	Texas RRC	9539	Feb-05	Regulatory Policy
141.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9613	Sep-05	Revenue Requirements
142.	SiEnergy, L.P.	Texas RRC	9604	Dec-05	Rate of Return, Income Taxes, and Cost Allocation
143.	ENSTAR Natural Gas Company	Alaska RCA	TA-140-4	Feb-06	Connection Fees
144.	SEMCO Energy	Michigan PSC	U-14984	May-06 Dec-06	Revenue Requirements
145.	Atmos Energy – Mid-Tex	Texas RRC	9676	May-06 Oct-06	Revenue Requirements
146.	EasTrans Limited Partnership	Texas RRC	9659	Jun-06	Rate of Return
147.	Kinder Morgan Texas Pipeline, L.P.	Texas RRC	9688	Jul-06	Rate of Return
148.	Crosstex CCNG Transmission Ltd.	Texas RRC	9660	Aug-06	Revenue Requirements
149.	Enbridge Pipelines (North Texas), LP	Texas RRC	9691	Oct-06	Rate of Return
150.	Panther Interstate Pipeline Energy	FERC	CP03-338-00	Mar-07	Revenue Requirements
151.	El Paso Electric Company	Texas PUC	34494	Jul-07	CCN
152.	El Paso Electric Company	NM PRC	07-00301-UT	Jul-07	CCN
153.	Atmos Energy	Kansas CC	08-ATMG-280-RTS	Sep-07 Feb-08	Rate of Return on Equity
154.	Centana Intrastate Pipeline LLC	Texas RRC	9759	Sep-07	Rate of Return
155.	Texas Gas Service Company	Texas RRC	9770	Nov-07	Rate of Return
156.	ENSTAR Natural Gas Company	Alaska RCA	U-08-25	Jun-08	Rate Class Switching
157.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-131-301	Oct-08	Rate of Return
158.	ExxonMobil Pipeline Co.	Alaska RCA	TL-140-304	Nov-08	Rate of Return
159.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9843	Dec-08	Revenue Requirements
160.	Koch Alaska Pipeline Company	Alaska RCA	TL 128-308	Dec-08	Rate of Return
161.	Unocal Pipeline Company	Alaska RCA	TL 118-312	Dec-08	Rate of Return

Bruce H. Fairchild
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
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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
187.	Enbridge Pipelines (Southern Lights)	FERC	IS11-146-000	Jun 11 Nov 11	Rate of Return
188.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-___	Jul 11	Rate of Return
189.	Unocal Pipeline Company	Alaska RCA	TL126-___	Dec 11	Rate of Return
190.	Kansas Gas Service	Kansas CC	12-KGSC-835-RTS	May 12 Oct 12	Rate of Return
191.	ExxonMobil Pipeline Co.	Alaska RCA	TL-157-304	Jun 12	Rate of Return
192.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-149-301	Jul 12	Rate of Return
193.	Seaway Crude Pipeline Company	FERC	IS12-226-000	Aug 12 Feb 13	Rate of Return
194.	Cross Texas Transmission, LLC	Texas PUC	40604	Aug 12 Oct 12 Nov 12	Revenue Requirements
195.	Wind Energy Transmission Texas	Texas PUC	40606	Aug 12 Nov 12	Revenue Requirements
196.	Lone Star Transmission LLC	Texas PUC	40798	Nov 12	Revenue Requirements
197.	West Texas Gas Company	Texas RRC	10235	Jan 13	Rate of Return
198.	Cross Texas Transmission, LLC	Texas PUC	41190	Feb 13	Revenue Requirements
199.	ExxonMobil Pipeline Co.	Alaska RCA	TL-162-304	Apr 13	Rate of Return
200.	EasTrans,LLC	Texas RRC	10276	Jul 13	Rate of Return
201.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-152-301	Jul 13	Rate of Return
202.	BP Pipelines (Alaska) Inc.	Alaska RCA	TL-143-311	Sep 13	Rate of Return
203.	Wind Energy Transmission Texas	Texas PUC	41923	Oct 13	Revenue Requirements
204.	Oliktok Pipeline Company	Alaska RCA	P-13-013	Nov 13	Rate of Return
205.	Aqua Texas Southeast Region-Gray	Texas CEQ	2013-2007-UCR	Apr 14	Revenue Requirements
206.	Entergy Mississippi	Mississippi PSC	EC-123-0082	Jun 14	Rate of Return on Equity
207.	Westlake Ethylene Pipeline	Texas RRC	10358	Jul 14 Aug 15	Rates
208.	ExxonMobil Pipeline Co.	Alaska RCA	TL-164-304	Jul 14	Rate of Return
209.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-154-301	Aug 14	Rate of Return
210.	ENSTAR Natural Gas Company	Alaska RCA	TA-262-4	Sep 14 Jun 15	Revenue Requirements, Cost Allocation, and Rate Design

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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
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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
233.	SiEnergy, LP	Texas RRC	10679	Jan 18	Rate of Return
234.	Targa Midland Gas Pipeline LLC	Texas RRC	10690	Jan 18	Revenue Requirements
235.	ET Fuel, LP	Texas RRC	10706	Apr 18	Revenue Requirements
236.	Texas Gas Service	Texas RRC	10739	Jun 18	Rate of Return
237.	Kansas Gas Service	Kansas CC	18-KGSG-560-RTS	Jun 18 Nov 18	Rate of Return on Equity
238.	Oliktok Pipeline Company	Alaska RCA	TL46-334	Jul 18	Rate of Return
239.	Red Bluff Express, LLC	Texas RRC	10752	Jul 18	Revenue Requirements
240.	PTE Pipeline LLC	Alaska RCA	P-18-0__	Jul 18	Rate of Return
241.	Agua Blanca, LLC	Texas RRC	10761	Aug 18	Revenue Requirements
242.	Texas Gas Service	Texas RRC	10766	Aug 18	Rate of Return
243.	Republic Transmission LLC	FERC	ER19-___	Dec 18	Formula Rates
244.	Gulf Coast Express Pipeline LLC	Texas RRC	10825	Feb 19	Revenue Requirements
245.	Cook Inlet Natural Gas Storage Alaska, LLC	Alaska RCA	U-18-043	Mar 19 Apr 19	Accumulated Deferred Income Taxes and Working Capital
246.	Impulsora Pipeline LLC	Texas RRC	10829	Mar 19	Revenue Requirements
247.	SEMCO Energy Gas Co.	Michigan PSC	U-20479	May 19 Oct 19	Revenue Requirements
248.	Liberty Utilities (Fox River) LLC	AAA	01-18-0002-2510	Jul 19 Oct 19	Revenue Requirements
249.	AMP Intrastate Pipeline LLC	Texas RRC	10887	Aug 19	Revenue Requirements
250.	Corix Utilities (Texas) Inc.	Texas PUC	49923	Aug 19 Jul 20 Aug 20	TCJA Tax Expense Reduction
251.	Colonial Pipeline Company	FERC	OR18-7-003	Nov 19 Feb 20 May 20 Jul 20	Rate of Return
252.	Texas Gas Service	Texas RRC	10928	Dec 19 Apr 20	Rate of Return
253.	Mississippi Power Company	Mississippi PSC	2019-UN-219	Feb 20	Rate of Return on Equity
254.	Corix Utilities (Texas)	Texas PUC	50557	Mar 20 Mar 21	Rate of Return and Excess ADFIT
255.	SouthCross CCNG Transmission	Texas RRC	10967	May 20	Revenue Requirements
256.	Kinder Morgan Border Pipeline LLC	Texas RRC	10980	Jun 20	Revenue Requirements

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

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257.	Monarch Utilities I LP	Texas PUC	50944	Jul 20 Nov 20	Rate of Return
258.	West Texas Gas, Inc.	Texas RRC	10998	Aug 20	Revenue Requirements, Rate of Return, and Cost of Service Study
259.	Centric Gas Services, LLC	Texas RRC		Oct 20	Rate of Return
260.	CoServ Gas, Ltd	Texas RRC	00005136	Nov 20	Rate of Return
261.	Permian Highway Pipeline LLC	Texas RRC	00005306	Dec 20	Revenue Requirements
262.	Whistler Pipeline LLC	Texas RRC	00005675	Feb 21	Revenue Requirements
263.	Oklahoma Natural Gas	Oklahoma CC	202100063	May 21 Oct 21	Rate of Return
264.	Oliktok Pipeline Company	Alaska RCA	TL47-334	Jul 21	Rate of Return
265.	Participating Gas Utilities	Texas RRC	00007061	Jul 21 Oct 21	Excess Gas Cost Securitization
266.	Texas Pipeline Webb County Lean System, LLC	Texas RRC	00008188	Nov 21	Revenue Requirements
267.	Legend Gas Pipeline LLC	Texas RRC	00008714	Jan 22	Revenue Requirements
268.	Oliktok Pipeline Company	Alaska RCA	TL48-334	Mar 22	Rate of Return
269.	Texas Gas Service	Texas RRC	00009896	Jun 22 Oct 22	Rate of Return
270.	ENSTAR Natural Gas Company	Alaska RCA	U-22-081	Aug 22 Jul 23	Income Taxes, Cost Allocation, and Rate Design
271.	Acacia Natural Gas, L.L.C.	Texas RRC	00010150	Aug 22	Revenue Requirements
272.	Corix Utilities (Texas)	Texas PUC	53815	Aug 22 Sep 23	Rate of Return, Cost Allocation, and Rate Design
273.	Oliktok Pipeline Company	Alaska RCA	TL50-334/51-334	Jan 23	Rate of Return
274.	Delaware-Permian Pipeline LLC	Texas RRC	00013058	Mar 23	Revenue Requirements
275.	SiEnergy LLC	Texas RRC	00013504	Mar 23	Rate of Return
276.	Texas Gas Service	Texas RRC	00014399	Jun 23	Rate of Return
277.	CoServ Gas, Ltd	Texas RRC	00014771	Jul 23	Rate of Return
278.	Matterhorn Express Pipeline, LLC	Texas RRC	00014719	Aug 23	Revenue Requirements
279.	TPL SouthTex Transmission Co. LP	Texas RRC	00015056	Aug 23	Revenue Requirements
280.	Kansas Gas Service	Kansas CC	24-KGSG-610-RTS	Mar 24	Rate of Return on Equity
281.	Delaware Link Ventures, LLC	Texas RRC	000124190	Mar 24	Revenue Requirements
276.	Texas Gas Service	Texas RRC	00017471	Jun 24	Rate of Return

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF BRUCE H. FAIRCHILD

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

1. "My name is Bruce H. Fairchild. I am over the age of eighteen (18) and fully competent to make this affidavit. The facts stated herein are true and correct based on my personal knowledge. My current position is principal in Financial Concepts and Applications, Inc.
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 H. Fairchild

SUBSCRIBED AND SWORN TO BEFORE ME by the said Bruce H. Fairchild on this 8th day of July 2024.

Notary Public, State of Texas

NOTARY PUBLIC STATE OF TEXAS
PHOEBE ORNELAS
MY COMMISSION EXPIRES
06/19/2027
NOTARY ID: 1021467-1

WEST TEXAS GAS UTILITIES LLC
RATE OF RETURN

OVERALL RATE OF RETURN

Capital Component	Percent of Total	Component Cost	Weighted Cost
Long-term Debt	34.40%	3.06%	1.05%
Common Equity	65.60%	10.75%	7.05%
Total	**100.00%**		**8.10%**

CAPITAL STRUCTURE

WTG DOWNSTREAM HOLDINGS LLC (a)

	December 31, 2023	
	Amount	Percent of Total
Debt	$ 152,670,914	34.40%
Equity	291,132,606	65.60%
Total	$ 443,803,520	**100.00%**

LDC PROXY GROUP (b)

	2023		2022		2021		2020	
Company	**Debt**	**Equity**	**Debt**	**Equity**	**Debt**	**Equity**	**Debt**	**Equity**
Atmos Energy	37.9%	62.1%	37.9%	62.1%	38.4%	61.6%	40.0%	60.0%
Chesapeake Utilities	48.8%	51.2%	41.0%	59.0%	41.5%	58.5%	42.2%	57.8%
New Jersey Resources	58.2%	41.8%	57.8%	42.2%	57.0%	43.0%	55.1%	44.9%
NiSource	52.2%	47.8%	55.7%	44.3%	56.9%	43.1%	61.6%	38.4%
Northwest Natural Gas	52.6%	47.4%	51.5%	48.5%	52.8%	47.2%	49.2%	50.8%
ONE Gas	43.8%	56.2%	50.7%	49.3%	61.1%	38.9%	41.5%	58.5%
Spire	54.9%	45.1%	51.2%	48.8%	52.5%	47.5%	49.0%	51.0%
LDC GROUP AVERAGE	**49.8%**	**50.2%**	**49.4%**	**50.6%**	**51.5%**	**48.5%**	**48.4%**	**51.6%**
Minimum	37.9%	41.8%	37.9%	42.2%	38.4%	38.9%	40.0%	38.4%
Maximum	58.2%	62.1%	57.8%	62.1%	61.1%	61.6%	61.6%	60.0%

(a) WTG Downstream Holdings LLL Audit Report (December 31, 2023).
(b) *The Value Line Investment Survey* "Ratings & Reports" (May 24, 2024).

	AGA									
	2022		2021		2020		2019		2018	
Common Equity	79,789	57.2%	73,052	56.4%	71,398	57.7%	66,682	58.1%	58,007	58.0%
Preferred Stock	24	0.0%	25	0.0%	25	0.0%	1,105	1.0%	62	0.1%
Long-term Debt	59,675	42.8%	56,413	43.6%	52,377	42.3%	47,058	41.0%	41,904	41.9%
	139,488	100.0%	129,490	100.0%	123,800	100.0%	114,845	100.0%	99,973	100.0%

COST OF DEBT

WTG DOWNSTREAM HOLDINGS LLC (a)

Description	Amount	Interest Rate	Annual Interest
Senior A Notes due 9/15/2026	$ 55,000,000	2.36%	$ 1,298,000
Senior B Notes due 9/15/2028	55,000,000	2.72%	1,496,000
Senior C Notes due 9/15/2028	45,000,000	2.99%	1,345,500
Debt Issuance Costs	(2,329,086)		538,746
Total	$ 152,670,914		$ 4,678,246
Cost of Debt		**3.06%**	

LDC PROXY GROUP (b)

Company	Cost of Debt
Atmos Energy	3.95%
Chesapeake Utilities	4.95%
New Jersey Resources	3.76%
NiSource	3.77%
Northwest Natural Gas	4.82%
ONE Gas	3.63%
Spire	4.14%
Average Cost of Debt	**4.14%**

(a) WTG Downstream Holdings LLL Audit Report (December 31, 2023).
(b) 2023 Form 10-Ks.

DCF MODEL -- DIVIDEND YIELD

Company	Ticker	Expected Dividend (a)	Price (b)	Dividend Yield (c)
Atmos Energy	ATO	$ 3.40	$ 117.06	2.90%
Chesapeake Utilities	CPK	$ 2.60	$ 110.38	2.36%
New Jersey Resources	NJR	$ 1.70	$ 43.83	3.88%
NiSource	NI	$ 1.08	$ 28.66	3.77%
Northwest Natural Gas	NWN	$ 1.95	$ 37.85	5.15%
ONE Gas	OGS	$ 2.66	$ 63.14	4.21%
Spire	SR	$ 3.09	$ 61.44	5.03%
AVERAGE				**3.90%**
MEDIAN				**3.88%**

(a) *The Value Line Investment Survey* "Summary & Index" (May 31, 2024).
(b) *Yahoo!* Finance (average of daily closing prices during May 2024).
(c) Expected Dividend / Price.

DCF MODEL -- EARNINGS GROWTH RATES

Company	Projected Growth: Value Line (a)	Projected Growth: I/B/E/S LSEG (b)	Projected Growth: Zacks (d)	Historical Growth: 10-Year (a)	Historical Growth: 5-Year (a)
Atmos Energy	7.0%	7.4%	7.0%	9.5%	9.0%
Chesapeake Utilities	6.5%	7.6%	N/R	9.0%	10.0%
New Jersey Resources	5.0%	N/R	N/R	5.0%	2.5%
NiSource	9.5%	7.4%	6.0%	1.5%	15.0%
Northwest Natural Gas	6.5%	N/R	N/R	-1.0%	2.5%
ONE Gas	3.5%	N/R	5.0%	N/R	6.0%
Spire	4.5%	6.4%	5.0%	5.0%	3.0%
AVERAGE	**6.1%**	**7.2%**	**5.8%**	**4.8%**	**6.9%**
MEDIAN	**6.5%**	**7.4%**	**5.5%**	**5.0%**	**6.0%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (May 24, 2024).
(b) LSEG Stock Reports Plus (May 30, 2024).
(d) Zacks.com "Snapshot" (Retrieved May 31, 2024).

N/R -- None reported.

DCF MODEL -- SUSTAINABLE GROWTH RATES

		2027-2029 Projected (a)				Shares Outstanding (a)		Earnings Retention Growth			External Financing Growth					
Company	Ticke	Earnings per Share	Dividends per Share	Book Value per Share	Price per Share	2023	Proj. 27-29	Retention Ratio	Return on Equity	"b x r"	2027-2029 Market-to-Book Ratio	Growth Rate in Shares	"s"	"v"	"s x v"	Sustainable Growth
Atmos Energy		$ 8.35	$ 4.25	$ 83.50	$ 137.50	148.49	175.00	49.1%	10.0%	4.9%	1.65	3.3%	5.5%	39.3%	2.2%	7.1%
Chesapeake Utilities		$ 7.00	$ 3.25	$ 70.70	$ 140.00	22.24	25.00	53.6%	9.9%	5.3%	1.98	2.4%	4.7%	49.5%	2.3%	7.6%
New Jersey Resources		$ 3.50	$ 1.95	$ 27.00	$ 60.00	97.57	100.00	44.3%	13.0%	5.7%	2.22	0.5%	1.1%	55.0%	0.6%	6.3%
NiSource		$ 2.20	$ 1.20	$ 20.40	$ 42.50	446.38	450.00	45.5%	10.8%	4.9%	2.08	0.2%	0.3%	52.0%	0.2%	5.1%
Northwest Natural Gas		$ 3.20	$ 1.98	$ 36.10	$ 62.50	37.63	45.00	38.1%	8.9%	3.4%	1.73	3.6%	6.3%	42.2%	2.7%	6.0%
ONE Gas		$ 5.00	$ 2.85	$ 60.20	$ 90.00	56.55	57.00	43.0%	8.3%	3.6%	1.50	0.2%	0.2%	33.1%	0.1%	3.6%
Spire		$ 5.50	$ 3.60	$ 66.05	$ 87.50	53.20	62.00	34.5%	8.3%	2.9%	1.32	3.1%	4.1%	24.5%	1.0%	3.9%
AVERAGE										**4.4%**					**1.3%**	**5.7%**
MEDIAN										**4.9%**					**1.0%**	**6.0%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (May 24, 2024).

DCF MODEL -- OTHER PROJECTED AND HISTORICAL GROWTH RATES

	Net Book Value (a)			Dividends per Share (a)			Price per Share		
	Pro-	Historical		Pro-	Historical		Pro-	Historical (b)	
Company	jected	10-Year	5-Year	jected	10-Year	5-Year	jected (a)	10-Year	5-Year
Atmos Energy	4.0%	9.5%	12.0%	7.5%	7.0%	8.5%	4.1%	8.8%	2.8%
Chesapeake Utilities	6.5%	10.5%	10.5%	8.0%	8.0%	10.0%	6.1%	10.0%	3.5%
New Jersey Resources	4.5%	7.5%	7.0%	5.0%	6.5%	6.5%	8.2%	5.5%	-2.3%
NiSource	5.0%	-3.0%	0.5%	4.5%	-0.5%	3.5%	10.4%	7.1%	0.5%
Northwest Natural Gas	4.0%	1.0%	0.5%	0.5%	1.5%	0.5%	13.4%	-1.5%	-11.2%
ONE Gas	4.5%	N/R	4.5%	2.5%	N/R	8.5%	9.3%	N/R	-6.4%
Spire	5.5%	5.5%	3.5%	4.5%	5.0%	5.5%	9.2%	2.9%	-6.2%
AVERAGE	**4.9%**	**5.2%**	**5.5%**	**4.6%**	**4.6%**	**6.1%**	**8.7%**	**5.4%**	**-2.8%**
MEDIAN	**4.5%**	**6.5%**	**4.5%**	**4.5%**	**5.8%**	**6.5%**	**9.2%**	**6.3%**	**-2.3%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (May 24, 2024).
(b) *Yahoo!* Finance (Average May 2014 and 2019 closing prices to average May 2024 closing price).

N/R -- None reported.

CAPITAL ASSET PRICING MODEL

Description	Historical Rates of Return (a)	Forward-Looking Rates of Return (b)
Market Required Rate of Return	12.04%	11.77%
Long-term Government Bond Return (a)(c)	4.87%	4.62%
Market Risk Premium (d)	7.17%	7.15%
LDC Group Beta (e)	0.88	0.88
LDC Group Risk Premium (f)	6.30%	6.28%
Risk-free Rate of Interest (c)	4.62%	4.62%
Theoretical CAPM Cost of Equity Estimate (g)	10.92%	10.90%
Size Premium (e)	1.99%	1.99%
CAPM Cost of Equity Estimates (h)	**12.91%**	**12.89%**

(a) *Kroll Cost of Capital Navigator.*
(b) Calculated by applying DCF model applied to S&P 500 firms paying dividends (May 21, 2024):

Expected Dividend Yield		1.72%
Projected Earnings Growth Rate:		
Value Line	9.24%	
I/B/E/S	10.23%	
Zacks	10.67%	
Average		10.05%
Market Required Rate of Return		11.77%

(c) May 2024 yield on 30-year U.S. Treasury bonds (Federal Reserve). 4.62%
(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 Theoretical CAPM Cost of Equity Estimate and Size Premium.

BOND RATINGS, BETA, MARKET CAPITALIZATION, AND SIZE PREMIUMS

Risk Measures

Company	Bond Rating S&P (a)	Bond Rating Moody's (b)	Beta (c)	Market-to Book Ratio	Market Capitalization (c) (millions)	Market Capitalization Premium(d)
Atmos Energy	A-	A1	0.85	1.60	$ 17,600	0.46%
Chesapeake Utilities	N/R	N/R	0.80	1.97	$ 2,500	1.21%
New Jersey Resources	N/R	A1	1.00	2.15	$ 4,400	0.95%
NiSource	BBB+	Baa2	0.95	1.26	$ 12,900	0.61%
Northwest Natural Gas	A+	Baa1	0.85	1.11	$ 1,500	1.39%
ONE Gas	A-	A3	0.85	1.29	$ 3,600	0.95%
Spire	BBB+	Baa2	0.85	1.22	$ 3,600	0.95%
LDC GROUP AVERAGE	**BBB+**	**A3**	**0.88**	**1.51**	**$ 6,586**	**0.93%**

CRSP Deciles Size Premiums (e)

Decile	Market Capitalization of Smallest Company (in millions)		Market Capitalization of Largest Company (in millions)	Size Premium (Return in Excess of CAPM)
1-Largest	$ 36,942.976	-	$ 2,662,326.048	-0.06%
2	14,910.719	-	36,391.113	0.46%
3	7,493.607	-	14,820.048	0.61%
4	4,622.261	-	7,461.284	0.64%
5	3,011.224	-	4,621.785	0.95%
6	1,864.293	-	3,010.806	1.21%
7	1,050.083	-	1,862.491	1.39%
8	555.880	-	1,046.037	1.14%
9	213.039	-	554.523	1.99%
10- Smallest	1.576	-	212.644	4.70%

(a) Moody's.com (Retreived June 5, 2024).
(b) StandardandPoors.com (Retrieved June 5, 2024).
(c) *The Value Line Investment Survey* "Ratings & Reports" (May 24, 2024).
(d) Kroll Cost of Capital Navigator (Retrieved February 19, 2024).

RISK PREMIUM METHOD

Year	Qtr.		Allowed ROE (a)	Average Utility Bond Yield (b)	Risk Premium	Year	Qtr.	Allowed ROE (a)	Average Utility Bond Yield (b)	Risk Premium
1980	1		13.45%	13.31%	0.14%	2003	1	11.38%	6.95%	4.43%
	2		14.38%	12.51%	1.87%		2	11.36%	6.41%	4.95%
	3		13.87%	12.74%	1.13%		3	10.61%	6.64%	3.97%
	4		14.35%	14.03%	0.32%		4	10.84%	6.43%	4.41%
1981	1		14.69%	14.64%	0.05%	2004	1	11.10%	6.14%	4.96%
	2		14.61%	15.48%	-0.87%		2	10.25%	6.53%	3.72%
	3		14.86%	16.36%	-1.50%		3	10.37%	6.18%	4.19%
	4		15.70%	16.01%	-0.31%		4	10.66%	5.95%	4.71%
1982	1		15.55%	16.51%	-0.96%	2005	1	10.65%	5.77%	4.88%
	2		15.62%	15.87%	-0.25%		2	10.52%	5.57%	4.95%
	3		15.72%	15.27%	0.45%		3	10.47%	5.51%	4.96%
	4		15.62%	13.67%	1.95%		4	10.40%	5.83%	4.57%
1983	1		15.41%	13.45%	1.96%	2006	1	10.63%	5.88%	4.75%
	2		14.84%	13.07%	1.77%		2	10.50%	6.35%	4.15%
	3		15.24%	13.38%	1.86%		3	10.45%	6.20%	4.25%
	4		15.41%	13.33%	2.08%		4	10.14%	5.89%	4.25%
1984	1		15.39%	13.64%	1.75%	2007	1	10.44%	5.92%	4.52%
	2		15.07%	14.80%	0.27%		2	10.12%	6.13%	3.99%
	3		15.37%	14.42%	0.95%		3	10.03%	6.27%	3.76%
	4		15.33%	13.26%	2.07%		4	10.27%	6.15%	4.12%
1985	1		15.03%	13.18%	1.85%	2008	1	10.38%	6.22%	4.16%
	2		15.44%	12.74%	2.70%		2	10.17%	6.41%	3.76%
	3		14.64%	11.92%	2.72%		3	10.49%	6.52%	3.97%
	4		14.44%	11.33%	3.11%		4	10.34%	7.46%	2.88%
1986	1		14.05%	10.05%	4.00%	2009	1	10.24%	6.78%	3.46%
	2		13.28%	9.35%	3.93%		2	10.11%	6.76%	3.35%
	3		13.09%	9.25%	3.84%		3	9.88%	5.86%	4.02%
	4		13.62%	9.17%	4.45%		4	10.27%	5.74%	4.53%
1987	1		12.61%	8.78%	3.83%	2010	1	10.24%	5.89%	4.35%
	2		13.13%	9.66%	3.47%		2	9.99%	5.73%	4.26%
	3		12.56%	10.45%	2.11%		3	9.93%	5.20%	4.73%
	4		12.73%	11.04%	1.69%		4	10.09%	5.43%	4.66%
1988	1		12.94%	10.50%	2.44%	2011	1	10.10%	5.66%	4.44%
	2		12.48%	10.66%	1.82%		2	9.85%	5.44%	4.41%
	3		12.79%	10.87%	1.92%		3	9.65%	4.91%	4.74%
	4		12.98%	9.94%	3.04%		4	9.88%	4.50%	5.38%
1989	1		12.99%	10.07%	2.92%	2012	1	9.63%	4.51%	5.12%
	2		13.25%	9.85%	3.40%		2	9.83%	4.39%	5.44%
	3		12.56%	9.38%	3.18%		3	9.75%	4.16%	5.59%
	4		12.94%	9.34%	3.60%		4	10.07%	4.04%	6.03%
1990	1		12.60%	9.62%	2.98%	2013	1	9.57%	4.27%	5.30%
	2		12.81%	9.82%	2.99%		2	9.47%	4.32%	5.15%
	3		12.34%	9.84%	2.50%		3	9.60%	4.84%	4.76%
	4		12.77%	9.76%	3.01%		4	9.83%	4.84%	4.99%
1991	1		12.69%	9.42%	3.27%	2014	1	9.54%	4.67%	4.87%
	2		12.53%	9.34%	3.19%		2	9.84%	4.44%	5.40%
	3		12.43%	9.20%	3.23%		3	9.45%	4.35%	5.10%
	4		12.38%	8.89%	3.49%		4	10.28%	4.24%	6.04%
1992	1		12.42%	8.76%	3.66%	2015	1	9.47%	3.90%	5.57%
	2		11.98%	8.72%	3.26%		2	9.43%	4.31%	5.12%
	3		11.87%	8.37%	3.50%		3	9.75%	4.62%	5.13%
	4		11.94%	8.44%	3.50%		4	9.68%	4.68%	5.00%
1993	1		11.75%	8.03%	3.72%	2016	1	9.48%	4.49%	4.99%
	2		11.71%	7.74%	3.97%		2	9.42%	4.05%	5.37%
	3		11.39%	7.25%	4.14%		3	9.47%	3.74%	5.73%
	4		11.15%	7.21%	3.94%		4	9.60%	4.17%	5.43%
1994	1		11.12%	7.53%	3.59%	2017	1	9.60%	4.26%	5.34%
	2		10.81%	8.28%	2.53%		2	9.47%	4.13%	5.34%
	3		10.95%	8.51%	2.44%		3	10.14%	3.97%	6.17%
	4	(c)	11.64%	8.89%	2.75%		4	9.68%	3.90%	5.78%
1995	2		11.00%	7.95%	3.05%	2018	1	9.68%	4.09%	5.59%
	3		11.07%	7.74%	3.33%		2	9.43%	4.32%	5.11%
	4		11.56%	7.36%	4.20%		3	9.69%	4.36%	5.33%
1996	1		11.45%	7.43%	4.02%		4	9.53%	4.57%	4.96%
	2		10.88%	7.98%	2.90%	2019	1	9.55%	4.37%	5.18%
	3		11.25%	7.96%	3.29%		2	9.73%	4.07%	5.66%
	4		11.32%	7.61%	3.71%		3	9.80%	3.53%	6.27%
1997	1		11.31%	7.80%	3.51%		4	9.73%	3.46%	6.27%
	2		11.70%	7.93%	3.77%	2020	1	9.35%	3.36%	5.99%
	3		12.00%	7.53%	4.47%		2	9.55%	3.21%	6.34%
	4	(c)	11.01%	7.26%	3.75%		3	9.52%	2.80%	6.72%
1998	2		11.37%	7.07%	4.30%		4	9.50%	2.89%	6.61%
	3		11.41%	6.94%	4.47%	2021	1	9.71%	3.18%	6.53%
	4		11.69%	6.89%	4.80%		2	9.48%	3.29%	6.19%
1999	1		10.82%	7.02%	3.80%		3	9.43%	2.99%	6.44%
	2	(c)	10.82%	7.43%	3.39%		4	9.59%	3.09%	6.50%
	4		10.33%	7.97%	2.36%	2022	1	9.38%	3.65%	5.73%
2000	1		10.71%	8.15%	2.56%		2	9.23%	4.68%	4.55%
	2		11.08%	8.30%	2.78%		3	9.52%	4.99%	4.53%
	3		11.33%	7.95%	3.38%		4	9.65%	5.66%	3.99%
	4		12.50%	7.97%	4.53%	2023	1	9.75%	5.33%	4.42%
2001	1		11.16%	7.68%	3.48%		2	9.45%	5.37%	4.08%
	2	(c)	10.75%	7.81%	2.94%		3	9.66%	5.72%	3.94%
	4		10.65%	7.70%	2.95%		4	9.63%	5.97%	3.66%
2002	1		10.67%	7.71%	2.96%	2023	1	9.78%	5.56%	4.22%
	2		11.64%	7.72%	3.92%					
	3		11.50%	7.37%	4.13%					
	4		10.78%	7.31%	3.47%					
						Average		**11.36%**	**7.55%**	**3.81%**

Unadusted:

Risk Premium = Intercept + (Slope X Interest Rate) (d)

RP	=	0.07271 +	-0.45770	X	5.78%
RP	=	0.07271 +	-0.02646		
RP	**=**	**4.63%**			

Adjusted (Using Iterative Prais-Winsten algorithm):

Risk Premium = Intercept + (Slope X Interest Rate) (d)

RP	=	0.07833 +	-0.53474	X	5.78%
RP	=	0.07833 +	-0.03091		
RP	**=**	**4.74%**			

(a) S&P Global Market Intelligence (various dates and data bases), Regulatory Research Associates (January 16, 1990), and Argus UtilityScope Regulatory Service (January 1986).
(b) Mergent Public Utility Manual (2003); Mergent Bond Record (September 2005); Moody's Credit Perspectives (Various Editions).
(c) No decisions reported for following quarter.
(d) Moody's Investor Services average utility bond yield for May 2024.

COMPARABLE EARNINGS METHOD

Company	Projected Earned Return on Book Equity (a)		
	2024	2025	2027-29
Atmos Energy	9.1%	9.4%	10.0%
Chesapeake Utilities	8.8%	8.8%	9.9%
New Jersey Resources	13.8%	13.1%	13.0%
NiSource	7.4%	8.2%	10.8%
Northwest Natural Gas	7.1%	8.2%	8.9%
ONE Gas	8.1%	8.1%	8.3%
Spire	8.4%	8.4%	8.3%
LDC GROUP AVERAGE	**8.9%**	**9.2%**	**9.9%**
MEDIAN	**8.4%**	**8.4%**	**9.9%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (May 24, 2024).

WORKPAPERS

TO

DIRECT TESTIMONY

OF

BRUCE H. FAIRCHILD

Workpapers to the Direct Testimony of Bruce H. Fairchild are voluminous and are being provided in electronic format.

PUBLIC NOTICE OF PROPOSED RATE CHANGE
NATURAL GAS UTILITY RATES

On July 16, 2024, West Texas Gas Utility, LLC ("WTGU" or the "Company"), filed a Statement of Intent to increase its gas utility rates with the Railroad Commission of Texas ("Commission") for the unincorporated areas within Andrews, Archer, Armstrong, Atascosa, Bailey, Bastrop, Bexar, Brewster, Briscoe, Brown, Caldwell, Carson, Castro, Cochran, Coleman, Collingsworth, Concho, Crosby, Culberson, Dallam, Dawson, Deaf Smith, Dimmit, Donley, Floyd, Frio, Gaines, Gray, Hale, Hall, Hansford, Hartley, Hemphill, Hockley, Hutchinson, Jeff Davis, Kimble, Kinney, La Salle, Lamb, Lipscomb, Lubbock, Lynn, McCulloch, Martin, Mason, Maverick, Medina, Menard, Moore, Ochiltree, Oldham, Parmer, Pecos, Potter, Presidio, Randall, Reeves, Roberts, Runnels, Sherman, Sutton, Swisher, Terry, Tom Green, Travis, Uvalde, Val Verde, Wheeler, Wilson, Winkler, Yoakum, and Zavala Counties and with the Cities of Amarillo, Balmorhea, Cactus, Canadian, Canyon, Claude, Dalhart, Darrouzett, Devine, Eden, Farwell, Follett, Groom, Higgins, Junction, Kermit, La Vernia, Lockhart, Lubbock, Luling, Menard, Miami, Mobeetie, Natalia, Paint Rock, Seguin, Shamrock, Somerset, Sonora, Stratford, Texhoma, Texline, Van Horn, Wheeler, White Deer, and Wolfforth, Texas ("Cities") for those incorporated areas. The proposed change in rates will affect all customers within the incorporated and unincorporated areas WTGU serves in the state of Texas that take service through WTGU's tariffed rates that are approved by a regulator. The proposed effective date of the requested change is August 20, 2024.

If approved, the proposed rates and tariffs are expected to increase the Company's jurisdictional annual revenue for the areas served by WTGU by $6,778,890 or approximately 35.75% including gas costs or 51.4% excluding gas cost. The proposed change in rates constitutes a "major change" as that term is defined in Section 104.101 of the Texas Utilities Code because the proposed changes will increase the total aggregate revenues of the Company by more than two and one-half percent. The proposed change in rates will not become effective until similar changes have become effective within the nearest incorporated city.

The Company proposes to implement the rates included in Table 1:

TABLE 1 – Proposed Rate Changes for Incorporated and Environs Customers

Customer Class	Number of Customers	Current Customer Charge***	Proposed Customer Charge	Current Volumetric Charge (Mcf)	Proposed Volumetric Charge (Mcf)
Domestic*	17,923	$23.42	$29.50	$4.84	$7.68
Non-Domestic**	2,485	$43.57	$79.00	$2.69	$4.89

*A Domestic customer typically refers to residential service.
**A Non-domestic customer does not receive service under the residential tariff and includes commercial, industrial customers, public authority customers, and non-profit customers.
*** Includes interim rate adjustment increase that is scheduled to go into effect on August 30, 2024.

TABLE 2 – Impact on Average Bill for Incorporated and Environs Customers

Customer Class and Gas Cost Zone (Average Monthly Usage Mcf)	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
North Zone					
Domestic	$73.96	$96.83	$22.87	30.9%	44.0%
Non-Domestic	$164.10	$240.97	$76.86	46.8%	81.6%
West Zone					
Domestic	$60.83	$80.67	$19.84	32.6%	42.3%
Non-Domestic	$179.22	$268.22	$89.01	49.7%	81.6%
South Zone					
Domestic	$42.50	$55.33	$12.83	30.2%	36.7%
Non-Domestic	$184.46	$272.60	$88.14	47.8%	81.6%

Avg Monthly Usage Mcf for the North gas cost zone is as follows: Domestic, 5.91 Mcf; Non-Domestic, 18.83 Mcf.

Avg Monthly Usage Mcf for the West gas cost zone is as follows: Domestic, 4.85 Mcf; Non-Domestic, 24.35 Mcf.

Avg Monthly Usage Mcf for the South gas cost zone is as follows: Domestic, 2.38 Mcf; Non-Domestic, 23.96 Mcf.

The amounts in Table 2 rely on the average cost of gas for 2023 in each gas zone as follows: North Zone, $3.71 per Mcf; West Zone, $2.88 per Mcf; and South Zone, $3.19 per Mcf.

The North Zone includes Unincorporated areas within the Counties of Armstrong, Carson, Collingsworth, Dallam, Deaf Smith, Donley, Gray, Hall, Hansford, Hartley, Hemphill, Hutchinson, Lipscomb, Moore, Ochiltree, Oldham, Potter, Randall, Roberts, Sherman, and Wheeler, and within the Cities of Amarillo, Cactus, Canadian, Canyon, Claude, Dalhart, Darrouzett, Farwell, Follett, Groom, Higgins, Miami, Mobeetie, Shamrock, Stratford, Texhoma, Texline, Wheeler, and White Deer.

The South Zone includes Unincorporated areas within the Counties of Atascosa, Bastrop, Bexar, Brown, Caldwell, Coleman, Concho, Dimmit, Frio, Kimble, Kinney, La Salle, Mason, Maverick, McCulloch, Medina, Menard, Runnels, Sutton, Tom Green, Travis, Uvalde, Val Verde, Wilson, and Zavala, and within the Cities of Devine, Eden, Junction, La Vernia, Lockhart, Luling, Menard, Natalia, Paint Rock, Seguin, Somerset, and Sonora.

The West Zone includes Unincorporated areas within the Counties of Andrews, Archer, Bailey, Brewster, Briscoe, Castro, Cochran, Crosby, Culberson, Dawson, Floyd, Gaines, Hale, Hockley, Jeff Davis, Lamb, Lubbock, Lynn, Martin, Parmer, Pecos, Presidio, Reeves, Swisher, Terry, Winkler, and Yoakum, and within the Cities of Balmorhea, Kermit, Lubbock, Van Horn, and Wolfforth.

In addition to the proposed rate changes for the Company's domestic and non-domestic customers, other proposed tariff changes include the addition of a new Winter Storm Cost Recovery Rider, removal of the EDIT Credit Rider, non-substantive changes to the Pipeline Safety Fee Rider, and other minor formatting changes.

The Company is also requesting Commission approval of new depreciation rates; a prudence determination for capital investment the Company has made through December 31, 2023; approval of a 51.22% allocation factor for capital investment costs that should be allocated to or recovered from Jurisdictional Customers for investment that benefits both Jurisdictional and Non-Jurisdictional Customers to be used in future interim rate adjustment ("IRA") filings; the approval of regulatory asset amounts comprised of costs related to Winter Storm Uri; recovery of the Winter Storm Uri regulatory asset through a monthly surcharge over 60 months; and approval to recover the reasonable rate case expenses associated with this filing through a surcharge on rates, as provided by law. The exact amount of rate case expenses and the surcharge amount will not be known until the case is complete.

Persons with specific questions or desiring additional information about this filing may contact West Texas Gas Utility, LLC at (432) 682-4349. Complete copies of the filed Statement of Intent, including all proposed rates, schedules and tariffs are available for inspection at WTGU's offices located at 303 Veterans Airpark Ln, Suite 5000, Midland, Texas 79705 and on our website at https://www.westtexasgas.com/texas-rate-case/. In addition, 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 the change would or has become effective, or September 19, 2024. Please reference Case No. OS-24-00017816. Any affected person within an incorporated area may contact his or her city council.

Este aviso tiene como fin informarles a los clientes de la División de West Texas Gas Utility, LLC que la Compañía ha presentado una solicitud para aumentar las tarifas del servicio público de gas. Esta solicitud afecta a todos los clientes domésticos y no domésticos en las áreas servidas por West Texas Gas Utility, LLC. Las personas que deseen hacer preguntas específicas o recibir más información sobre esta solicitud pueden comunicarse con la Compañía llamando al (432) 682-4349. Cualquier persona afectada puede presentar por escrito comentarios o una protesta sobre el cambio de tarifas propuesto 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 30 días siguientes a la fecha en que este cambio entraría en vigencia. Por favor haga referencia a Case No. OS-24-00017816. Cualquier persona afectada dentro de un área incorporada puede contactar a su Consejo Municipal.

WEST TEXAS GAS UTILITY, LLC,
STATEMENT OF INTENT TO INCREASE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF TEXAS
PROTECTIVE AGREEMENT

This Protective Agreement shall govern the use of all information deemed confidential or highly sensitive confidential information by a party responding to discovery requests, filing testimony, or otherwise providing information during the above-referenced municipal statement of intent proceeding, 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.

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 West Texas Gas Utility, LLC ("WTGU"), including WTGU or a representative for a city within the Texas Area, or other party with standing to participate in the proceeding.

4. Definition of "producing party"

A "producing party" is defined for purposes of this Protective Agreement as WTGU, a city within the Texas Area, or any other party with standing to participate in the proceeding.

5. Access to Protected Materials

A reviewing party shall be permitted access to protected materials only through its authorized representatives. "Authorized representatives" of a party include its counsel of record in this proceeding and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by the party and directly engaged in these proceedings, provided that such person has signed the certification required by Paragraph 8.

6. Designation of Highly Sensitive Protected Materials

The term "highly sensitive protected materials" is a subset of "protected materials." The term refers to, but is not limited to, documents and information the provision of which to the reviewing party or its authorized representatives would: (1) expose the producing party or any of its affiliates to an unreasonable risk of harm, or (2) would result in disclosure of information that would be subject to a privilege against disclosure, a contractual confidentiality agreement or other Protective Agreement. 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 or Regulatory authority 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.

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

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

TABLE OF CONTENTS

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

BASE RATE REVENUE REQUIREMENTS

Description	Reference Schedule	Adjusted Texas Amounts		Jurisdictional Domestic	Jurisdictional Non-Domestic	Non-Jurisdictional
O&M Expenses	Schedule B-1		10,696,368	6,209,274	1,595,221	2,891,873
A&G Expenses	Schedule B-2		5,576,542	3,432,439	952,287	1,191,816
Taxes Other than Income	Schedule B-3		2,792,222	1,633,544	445,390	713,288
Depreciation Expense	Schedule D		5,211,043	2,959,015	975,652	1,276,376
Return on Investment						
Rate Base	Schedule C	119,850,523				
Rate of Return	Schedule E	8.10%				
Return	Schedule F		9,713,453	5,795,757	1,995,774	1,921,923
Net Income Tax Expense	Schedule F		1,713,989	1,022,691	352,165	339,133
Other Gas Income	Schedule G		(1,087,324)	(685,011)	(218,067)	(184,245)
Base Rate Revenue Requirements			**34,616,294**	**20,367,710**	**6,098,421**	**8,150,163**
Base Rate Revenues at Current Rates	Schedule A-2			**10,183,324**	**3,005,044**	
Base Rate Revenues at Requested Rates	Schedule A-2			**14,510,622**	**5,456,636**	
Cost-Based Rate Increase:						
Amount	Schedule A-2			**10,184,386**	**3,093,378**	
Percentage				**100.0%**	**102.9%**	
WGTU Proposed Rate Increase:						
Amount	Schedule A-2			**4,327,298**	**2,451,592**	
Percentage				**42.5%**	**81.6%**	

WEST TEXAS GAS UTILITY, LLC **Schedule A-1**
Test Period Ending December 31, 2023 **Page 1 of 1**

CALCULATION OF COST-BASED RATES

		DOMESTIC CUSTOMERS		NON-DOMESTIC CUSTOMERS	
Description	**Reference**	**Base Rate Calculation**	**Cost of Service**	**Base Rate Calculation**	**Cost of Service**
Cost of Service	Schedule J-B				
Customer-related Costs			15,405,551		2,470,463
Capacity-related Costs			4,962,159		3,627,958
Total Cost of Service			**20,367,710**		**6,098,421**
Monthly Customer Charge:					
Customer-related Costs			15,405,551		2,470,463
Number of Customers	Schedule K	17,924		2,484	
Months per year		12		12	
Annual No. of Bills			215,084		29,805
Cost-based Monthly Customer Charge			**$ 71.63**		**$ 82.89**
Consumption Charge:					
Capacity-related Costs			4,962,159		6,098,421
Annual Volumes -- Mcf	Schedule K		1,063,235		634,364
Cost-based Consumption Charge			**$ 4.67**		**$ 9.61**

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

Schedule A-2
Page 1 of 1

BASE RATE REVENUE COMPARISON AT CURRENT, COST-BASED, AND PROPOSED RATES

Description	Reference	Current Base Rates			Cost-Based Base Rates		Proposed Base Rates	
		Unadjusted	Weather Adjustment	Adjusted	Cost-Based	% Increase	Proposed	% Increase
Domestic Customers								
Number of Domestic Customers	Schedule K	17,924		17,924	17,924		17,924	
Months per year		12		12	12		12	
Annual No. of Bills		215,084		215,084	215,084		215,084	
Domestic Customer Charge		$ **23.42**		$ **23.42**	$ **71.63**	**205.8%**	$ **29.50**	**26.0%**
Monthly Customer Charge Revenues		**5,037,267**		**5,037,267**	**15,405,551**		**6,344,978**	
Domestic Volumes -- Mcfs	Schedule K	1,007,056	56,179	1,063,235	1,063,235		1,063,235	
Domestic Consumption Charge		$ **4.84**		$ **4.84**	$ **4.67**	**-3.6%**	$ **7.68**	**58.7%**
Consumption Charge Revenues		**4,874,153**		**5,146,057**	**4,962,159**		**8,165,644**	
Total Domestic Revenues		**9,911,420**		**10,183,324**	**20,367,710**	**100.0%**	**14,510,622**	**42.5%**
Non-Domestic Customers								
Number of Non-Domestic Customers	Schedule K	2,484		2,484	2,484		2,484	
Months per year		12		12	12		12	
Annual No. of Bills		29,805		29,805	29,805		29,805	
Non-Domestic Customer Charge		$ **43.57**		$ **43.57**	$ **82.89**	**90.2%**	$ **79.00**	**81.3%**
Monthly Customer Charge Revenues		**1,298,604**		**1,298,604**	**2,470,463**		**2,354,595**	
Non-Domestic Volumes -- Mcfs	Schedule K	601,671	32,693	634,364	634,364		634,364	
Non-Domestic Consumption Charge		$ **2.69**		$ **2.69**	$ **9.61**	**257.4%**	$ **4.89**	**81.8%**
Consumption Charge Revenues		**1,618,495**		**1,706,440**	**6,098,421**		**3,102,041**	
Total Non-Domestic Revenues		**2,917,099**		**3,005,044**	**8,568,884**	**185.2%**	**5,456,636**	**81.6%**
TOTAL JURISICTIONAL REVENUES		**12,828,519**		**13,188,368**	**28,936,594**	**119.4%**	**19,967,258**	**51.4%**

WEST TEXAS GAS, INC.
Test Period Ending December 31, 2019

Corrected Schedule A-3
Page 1 of 1

SUMMARY OF ADJUSTMENTS

Purpose of Adjustment	Affected Accounts	Reference	Amount of Adjustment
Revenues			
To weather normalize volumes	Domestic Customers	Schedules A-2 and K	271,904
To weather normalize volumes	Non-Domestic Customers	Schedules A-2 and K	87,945
O&M Expenses			
To remove amounts related to Oklahoma operations	All O&M expense accounts	Schedules B-1 and B-4	(1,131,411)
To remove gas transportation costs included in cost of gas	Account 858 - Trans. & Comp. of Gas by Others	Schedule B-1	(347,264)
To remove Donations and Contributions	Account 888 -- Other Expenses	Schedules B-1 and H-5	(26,370)
A&G Expenses			
To remove amounts related to Oklahoma operations	All A&G expense accounts	Schedules B-2 and B-4	(612,508)
To include Interest expense on Customer Deposits	Account 910 -- Customer Service Expense	Schedule B-2	30,504
To remove Penalties and Fines	Account 921 -- Office Supplies and Expenses	Schedules B-2 and H-7	(24,117)
To remove Entertainment, Meals, Lodging, and Travel expenses.	Account 921 -- Office Supplies and Expenses	Schedule B-2	(35,971)
To remove Lobbying expenses	Account 923 -- Outside Services Employed	Schedules B-2 and H-6	(10,219)
To remove Donations and Contributions	Account 930 -- Miscellaneous General Expenses	Schedules B-2 and H-5	(38,070)
To remove Entertainment, Meals, Lodging, and Travel expenses.	Account 930 -- Miscellaneous General Expenses	Schedule B-2	(166,469)
Taxes Other than Income			
To remove amounts related to Oklahoma operations	All Other Tax accounts except Texas Franchise	Schedules B-3 and B-4	(426,667)
Rate Base			
Plant in Service			
To remove plant related to Oklahoma operations	Various plant accounts	Schedules C and C-1	(19,170,874)
To remove acquisition adjustments	Account 303	Schedules C and C-1	(20,621,198)
To remove non-utility assets	Accounts 332 and 389.1	Schedules C and C-1	(1,293,000)
To reclassify assets.	Accounts 366,369,392,394,396,398	Schedules C and C-1	0
To remove retired assets.	Accounts 391,392,394,397,398	Schedules C and C-1	(1,397,372)
Accumulated Depreciation			
To remove acc. depreciation related to Oklahoma operations	Various plant accounts	Schedules C and C-2	(8,413,221)
To remove acquisition adjustments	Account 303	Schedules C and C-2	(3,798,361)
To reclassify assets.	Accounts 366,369,392,394,396,398	Schedules C and C-2	-
To remove retired assets.	Accounts 391,392,394,397,398	Schedules C and C-2	(1,988,539)
Working Capital			
To adjust December 31, 2023 balance to test year average	Account 165 -- Prrepayments	Schedules C and C-3	258,321
To adjust December 31, 2023 balance to test year average	Account 154 -- Plant Materials and Operating Supplies	Schedules C and C-3	68,456
Non-Investor Supplied Capital			
To record Accumulated Deferred Income Taxes	Account 281 -- Accumulated DIT -- Accelerated Depreciation	Schedules C	(25,703,718)
To record Excess Accumulated Deferred Income Taxes	Account 283 -- Accumulated DIT -- Other	Schedules C and C-4	(9,311,525)
Depreciation Expense			
To reflect proposed depreciation rates	Account 403 -- Depreciation Expense	Schedule D	(656,628)
Other Income			
To remove other income related to Oklahoma operations	Account 488 -- Miscellaneous Service Revenues	Schedule G-1	(205,742)

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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EXPENSES BY MONTH (a)

Acct. No.	Description	2023 January	February	March	April	May	June	July	August	September	October	November	December	Total
	OPERATIONS AND MAINTENANCE EXPENSES													
	Transmission Expense													
813.0	Other Gas Supply Expenses	3,100	2,091	10,457	-	33,832	-	-	2,960	30,057	44	36,502	38,120	157,163
858.0	Trans. & Comp. Of Gas by Others	18,560	20,549	27,861	33,136	32,780	34,711	32,535	35,800	35,977	29,771	27,101	18,484	347,264
863.0	Maintenance of Mains	140	28,843	53,492	45,102	2,358	27,875	19,330	13,934	17,412	16,818	2,639	(130,789)	97,154
	Distribution Expense													
870.0	Operation Supervision & Engineering	561,280	595,023	889,984	591,813	594,268	593,465	626,737	966,379	642,027	610,049	609,516	498,143	7,778,684
874.0	Mains and Services Expenses	106,346	116,608	136,290	115,543	34,400	171,761	200,749	54,978	131,323	126,409	34,389	(30,389)	1,198,406
880.0	Other Expenses	80,080	69,386	83,518	75,622	50,883	68,623	121,295	75,822	82,647	39,946	84,941	80,702	913,465
881.0	Rents	22,345	19,308	15,118	13,585	16,738	14,202	17,150	20,917	17,807	20,522	19,656	21,973	219,320
886.0	Maintenance of Structures	437	5,474	396	548	-	39	-	62	529	2,009	21	14	9,528
887.0	Maintenance of Mains	12,433	65,917	19,584	25,328	8,740	25,060	12,527	69,605	57,225	69,256	39,207	22,423	427,305
888.0	Maint of M&R Station Equip-General	726	-	31	-	-	725	173	725	28	-	-	-	2,407
889.0	Maint of M&R Station Equip-City Gate	92,943	114,499	65,640	47,570	15,487	101,614	39,156	164,799	170,722	52,328	53,601	(416,699)	501,661
894.0	Maintenance of Other Equipment	54,537	29,913	36,960	27,275	20,712	45,273	48,039	25,918	83,871	46,185	45,403	84,968	549,056
	ADMINISTRATIVE AND GENERAL EXPENSES													
	Customer Service and Sales Expenses													
904.0	Uncollectible Accounts	20,875	13,820	16,046	16,293	13,034	8,956	17,800	23,506	16,814	11,853	11,174	10,441	180,612
910.0	Miscellaneous Customer Service Exp	753	4,937	54,533	33,807	1,100	500	799	3,963	150	-	1,150	-	101,692
913.0	Advertising Expenses	879	6,384	1,682	2,195	1,543	2,096	84	1,225	1,787	2,144	-	1,374	21,392
	Administrative and General Expenses													
920.0	Administrative and General Salaries	101,032	106,422	160,695	104,682	104,043	103,336	101,969	106,384	67,449	107,485	107,317	196,228	1,367,041
921.0	Office Supplies and Expenses	21,804	6,985	15,163	14,213	27,450	11,376	64,583	13,343	28,725	9,083	14,773	27,832	255,330
922.0	Administrative Expenses Transferred-Credit	-	-	-	-	-	-	-	-	-	-	-	(1,230,375)	(1,230,375)
923.0	Outside Services Employed	125,321	83,284	101,836	204,721	116,558	222,752	142,962	159,546	88,163	144,491	110,032	163,351	1,663,018
924.0	Property Insurance	50,429	50,429	61,476	54,097	55,965	171,012	87,174	85,506	85,506	121,437	84,704	47,055	954,789
926.0	Employee Pension and Benefits	128,813	114,756	168,295	115,522	123,002	113,014	117,597	168,138	130,170	142,366	115,176	123,505	1,560,354
930.0	Miscellaneous General Expense	101,164	109,490	132,188	270,999	79,846	67,410	121,125	139,768	192,231	134,612	143,735	60,090	1,552,657
931.0	Rents	4,690	1,544	-	1,547	-	-	-	-	2,740	1,627	-	(5,266)	6,882
	TAXES OTHER THAN INCOME													
	Payroll Taxes:													
408.2	Payroll Taxes	68,363	64,164	54,727	51,653	51,647	51,430	53,760	78,580	51,451	51,268	50,781	48,520	676,344
	Property Taxes:													
408.2	Property Taxes	132,973	132,973	132,922	136,398	132,973	551,770	159,139	132,973	132,973	162,517	133,162	432,187	2,372,959
	Other Taxes:													
408.2	Texas Franchise Tax	-	-	-	42,064	-	-	-	-	-	-	9,967	-	52,031
408.2	Miscellaneous	12,865	23,693	6,682	4,327	16,358	3,015	2,936	14,329	2,865	14,731	5,718	10,036	117,555

(a) WTG books and records (detail is contained in electronic workpapers provided separately).

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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OPERATIONS AND MAINTENANCE EXPENSES

Acct. No.	Description	Test Year WTG Total (a)	Adjustments	Ref.	Oklahoma (d)	Adjusted Texas
	Transmission Expense					
813.0	Other Gas Supply Expenses	157,163	-		-	157,163
858.0	Trans. & Comp. Of Gas by Others	347,264	(347,264)	(b)	-	-
863.0	Maintenance of Mains	97,154	-		(733)	96,421
		-				
	Distribution Expense	-				
870.0	Operation Supervision & Engineering	7,778,684	-		(811,654)	6,967,030
874.0	Mains and Services Expenses	1,198,406	-		(78,991)	1,119,415
880.0	Other Expenses	913,465	(26,370)	(c)	(97,238)	789,857
881.0	Rents	219,320	-		(18,624)	200,696
886.0	Maintenance of Structures	9,528	-		(2,000)	7,528
887.0	Maintenance of Mains	427,305	-		(32,093)	395,212
888.0	Maint of M&R Station Equip-General	2,407	-		(158)	2,249
889.0	Maint of M&R Station Equip-City Gate	501,661	-		(61,250)	440,411
894.0	Maintenance of Other Equipment	549,056	-		(28,671)	520,385
	Totals	**12,201,412**	**(373,633)**		**(1,131,411)**	
	Operation & Maintenance Expenses					**10,696,368**

(a) Schedule B.
(b) To remove amounts included in cost of gas.
(c) To remove donations and contributions (Schedule H-5).

WEST TEXAS GAS UTILITY, LLC **Schedule B-2**
Test Period Ending December 31, 2023 **Page 1 of 1**

ADMINISTRATIVE AND GENERAL EXPENSES

Acct. No.	Description	Test Year WTG Total (a)	Adjustments	Ref.	Oklahoma (g)	Adjusted Texas
	Customer Service and Sales Expenses					
904.0	Uncollectible Accounts	180,612	-		(17,862)	162,750
910.0	Miscellaneous Customer Service Exp	101,692	30,504	(b)	(8,372)	123,824
913.0	Advertising Expenses	21,392	-		(239)	21,153
	Administrative and General Expenses					
920.0	Administrative and General Salaries	1,367,041	-		(125,499)	1,241,542
921.0	Office Supplies and Expenses	255,330	(60,088)	(c)(d)	(21,931)	173,311
922.0	Administrative Expenses Transferred-Credit	(1,230,375)	-		112,952	(1,117,423)
923.0	Outside Services Employed	1,663,018	(10,219)	(e)	(152,671)	1,500,128
924.0	Property Insurance	954,789	-		(87,653)	867,137
926.0	Employee Pension and Benefits	1,560,354	-		(142,225)	1,418,128
930.0	Miscellaneous General Expense	1,552,657	(204,539)	(d)(f)	(167,769)	1,180,349
931.0	Rents	6,882	-		(1,240)	5,641
	Totals	**6,433,393**	**(244,343)**		**(612,508)**	
	Administrative and General Expenses					**5,576,542**

(a) Schedule B.
(b) To include interest on customer deposits.
(c) To remove penalties and fines (Schedule H-7).
(d) To remove entertainment, meals, lodging, and travel expenses.
(e) To remove lobbying expenses (Schedule H-6).
(f) To remove donations and contributions (Schedule H-5).
(g) Composite Corporate Allocation Factor (Schedule B-4).

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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TAXES OTHER THAN INCOME

Acct. No.	Description	Test Year WTG Total (a)	Adjustments	Ref.	Oklahoma (b)	Adjusted Texas
	Payroll Taxes:					
408.2	Payroll Taxes	676,344	-		(74,266)	602,078
	Property Taxes:					
408.2	Property Taxes	2,372,959	-		(345,921)	2,027,037
	Other Taxes:	-				
408.2	Texas Franchise Tax	52,031	-		-	52,031
408.2	Miscellaneous	117,555	-		(6,479)	111,076
	Totals	**3,218,888**	**-**		**(426,667)**	
	Taxes Other than Income					**2,792,222**

(a) Schedule B.
(b) Schedule B-4.

WEST TEXAS GAS UTILITY, LLC **Schedule B-4**
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ALLOCATION OF O&M, A&G, AND OTHER TAXES TO OKLAHOMA

Acct. No.	Description	Region 40 Total (a)	Region 40 Oklahoma	Region 70 Total (a)	Region 70 Oklahoma	WTGU Total (a)	WTGU Oklahoma	Total Oklahoma
	Allocation Factors:							
	Average Number of Customers (a)	4,312	78	6,633	4,509	28,108	4,587	
	Oklahoma Customers as % of Total		**1.81%**		**67.98%**		16.32%	
	Gross Plant (Schedule C-1)					291,649,056	19,170,874	
	Oklahoma Plant as % of Total						6.57%	
	O&M Expenses (Schedule B-1)					11,827,779	1,131,411	
	Oklahoma O&M Expenses as % of Total						9.57%	
	Revenues (a)					144,743,978	6,170,411	
	Oklahoma Revenues as % of Total						4.26%	
	Composite Corporate Allocation Factor						**9.18%**	
	Operations and Maintenance Expenses (b)							
813.0	Other Gas Supply Expenses	-	-	-	-	-	-	-
858.0	Trans. & Comp. Of Gas by Others	-	-	-	-	-	-	-
863.0	Maintenance of Mains	40,529	733	-	-	-	-	733
870.0	Operation Supervision & Engineering	1,080,587	19,547	1,155,069	785,196	75,278	6,911	811,654
874.0	Mains and Services Expenses	84,852	1,535	113,943	77,456	-	-	78,991
880.0	Other Expenses	126,267	2,284	139,755	95,003	(538)	(49)	97,238
881.0	Rents	10,508	190	27,118	18,434	-	-	18,624
886.0	Maintenance of Structures	1,942	35	2,890	1,965	-	-	2,000
887.0	Maintenance of Mains	31,925	577	46,361	31,515	-	-	32,093
888.0	Maint of M&R Station Equip-General	2,234	40	173	118	-	-	158
889.0	Maint of M&R Station Equip-City Gate	96,361	1,743	87,538	59,507	-	-	61,250
894.0	Maintenance of Other Equipment	45,917	831	38,519	26,185	18,034	1,656	28,671
	Total	1,521,122	27,516	1,611,366	1,095,379	92,774	8,517	1,131,411
	Administrative and General Expenses (c)							
904.0	Uncollectible Accounts	10,807	195	25,989	17,667	-	-	17,862
910.0	Miscellaneous Customer Service Exp	-	-	-	-	91,190	8,372	8,372
913.0	Advertising Expenses	435	8	340	231	-	-	239
920.0	Administrative and General Salaries	-	-	-	-	1,367,041	125,499	125,499
921.0	Office Supplies and Expenses	-	-	-	-	238,887	21,931	21,931
922.0	Administrative Expenses Transferred-Credi	-	-	-	-	(1,230,375)	(112,952)	(112,952)
923.0	Outside Services Employed	-	-	-	-	1,663,018	152,671	152,671
924.0	Property Insurance	-	-	-	-	954,789	87,653	87,653
926.0	Employee Pension and Benefits	-	-	894	607	1,542,625	141,618	142,225
930.0	Miscellaneous General Expense	100,598	1,820	201,727	137,130	313,926	28,819	167,769
931.0	Rents	-	-	-	-	13,512	1,240	1,240
	Total	111,840	2,023	228,949	155,635	4,954,613	454,850	612,508
	Taxes Other than Income (c)							
408.2	Payroll Taxes	80,998	1,465	86,157	58,568	155,038	14,233	74,266
408.2	Property taxes	104,308	1,887	506,094	344,034	-	-	345,921
408.2	Other	17,360	314	9,070	6,165	-	-	6,479
		202,666	3,666	601,321	408,768	155,038	14,233	426,667

(a) Schedule K and WTG books and records (detail is contained in electronic workpapers provided separately).
(b) Allocated based on number of customers.
(c) Regions 40 and 70 allocated based on number of customers; Corporate allocated using composite allocation factor.

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

RATE BASE

Description	Reference	December 31, 2023 WTG Total	Oklahoma	Texas	Adjustments	Ref.	Adjusted Texas
Plant in Service:							
Plant in Service	Schedule C-1	291,649,056	(19,170,874)	272,478,182	(23,311,570)		249,166,612
Accumulated Depreciation	Schedule C-2	(87,190,168)	8,413,221	(78,776,946)	5,786,900		(72,990,047)
Net Plant in Service		204,458,888		193,701,235			176,176,565
Construction Work in Progress	(a)	5,407,013	-	5,407,013	(5,407,013)	(b)	-
Working Capital:							
Cash Working Capital Allowance		-	-	-	-	(c)	-
Prepayments	Schedule C-3	1,016,495	(93,318)	923,177	258,321	(d)	1,181,498
Materials and Supplies Inventories	Schedule C-3	1,963,405	(180,247)	1,783,158	68,456	(d)	1,851,614
Non-Investor Supplied Capital:							
Customer Deposits	(a)	(1,508,997)	308,437	(1,200,560)	-		(1,200,560)
Contributions in Aid of Construction	(a)	(23,804,581)	661,231	(23,143,350)	-		(23,143,350)
Accumulated Deferred Income Taxes		-	-	-	(25,703,718)	(e)	(25,703,718)
Excess ADIT	Schedule C-4				(9,311,525)		(9,311,525)
RATE BASE							**119,850,523**

(a) WTG books and records (detail is contained in electronic workpapers provided separately).
(b) No construction work in progress (CWIP) is being requested to be included in rate base.
(c) No cash working capital allowance is being requested to be included in rate base.
(d) To adjust December 31, 2023 balance to average during the test year.
(e) To record Accumulated Deferred Income Taxes (ADIT) at December 31, 2023:

Total Net Plant in Service	204,458,888	
Net Tax Basis of Total Plant in Service (a)	34,102,237	
Timing Difference		170,356,651
Corporate Income Tax Rate		21%
Total ADIT Liability		**35,774,897**
Adjusted Texas Plant in Service	249,166,612	
Total Plant in Service	291,649,056	
Percent Applicable to Texas		85.43%
Texas ADIT Liability		**30,563,822**
Texas Contributions in Aid of Construction	23,143,350	
Corporate Income Tax Rate	21%	
Texas ADIT Asset		4,860,104
Net Texas ADIT Liability		**25,703,718**

WEST TEXAS GAS UTILITY, LLC **Schedule C-1**
Test Period Ending December 31, 2023 **Page 1 of 1**

PLANT IN SERVICE

Acct. No.	Description	12/31/2023 WTGU Total (a)	Oklahoma Direct (a)	Oklahoma Allocated (b)	Texas	Adjustments	Ref.	Adjusted Texas
	Production and Gathering Plant							
301.0	Organization	57,872	-	-	57,872			57,872
302.0	Franchises and Consents	200,000	-	-	200,000			200,000
303.0	Intangible Plant	22,388,083	(1,388,571)	(36,449)	20,963,064	(20,621,198)	(c)	341,866
332.0	Field Lines	3,048,811	-	-	3,048,811	(1,000)	(d)	3,047,811
334.0	Field M&R Station Equipment	100,000	-	-	100,000			100,000
	Transmission Plant							
365.0	Land and Rights-of-Way	5,379,123	-	-	5,379,123			5,379,123
366.0	Structures and Improvements	149,596	-	-	149,596	(149,596)	(e)	-
367.0	Mains	45,312,827	-	-	45,312,827			45,312,827
368.0	Compressor Station Equipment	38,984	-	-	38,984			38,984
369.0	M&R Station Equipment	1,263,865	-	-	1,263,865	149,596	(e)	1,413,460
371.0	Other Equipment	224,148	-	-	224,148			224,148
	Distribution Plant							
376.0	Mains	183,679,328	(15,777,824)	(1,840)	167,899,665			167,899,665
377.0	Compressors	358,854	(638)	-	358,216			358,216
378.0	M&R Station Equipment - General	8,597,576	(899,062)	(5,545)	7,692,969			7,692,969
387.0	Other Equipment	815,942	(127,844)	(463)	687,636			687,636
	General Plant							
389.0	Rights-of-Way	6,308,629	-	-	6,308,629			6,308,629
389.1	Land	1,500,401	(12,000)	(5,519)	1,482,882	(1,292,000)	(d)	190,882
390.0	Office Buildings	4,604,940	(42,094)	-	4,562,846			4,562,846
391.0	Office Furniture and Equipment	454,910	(32,125)	(1,259)	421,526	(149,149)	(f)	272,377
392.0	Transportation Equip	4,546,739	(432,484)	(12,419)	4,101,836	(1,201,649)	(e)(f)	2,900,187
394.0	Tools, Shop & Garage	1,524,133	(77,981)	(51,188)	1,394,965	(232,380)	(e)(f)	1,162,584
396.0	Power Operated Equipment	-	-	-	-	356,492	(e)	356,492
397.0	Communication Equip	583,845	-	(6,354)	577,490	(54,358)	(f)	523,132
398.0	Miscellaneous Equip	510,451	(233,724)	(25,493)	251,234	(116,328)	(e)(f)	134,907
	Plant in Service	**291,649,056**	**(19,024,346)**	**(146,528)**	**272,478,182**	**(23,311,570)**		**249,166,612**

(a) From WTGU books and records.
(b) Allocation of corporate general plant to Oklahoma:

		Corporate		Oklahoma
	Oklahoma Plant as % of Total			6.52%
303.0	Intangible Plant	558,767		36,449
367.0	Mains	-		
371.0	Other Equipment	28,206		-
376.0	Mains	85,009		1,840
378.0	M&R Station Equipment - General	7,092		5,545
387.0	Other Equipment	84,601		463
389.1	Land	19,300		5,519
391.0	Office Furniture and Equipment	190,394		1,259
392.0	Transportation Equip	784,721		12,419
394.0	Tools, Shop & Garage	97,414		51,188
397.0	Communication Equip	390,808		6,354
398.0	Miscellaneous Equip	17,602		25,493
	Total	2,263,915	-	146,528

(c) To remove acquisition adjustments.
(d) To remove non-utiliy assets.
(e) To reclassify assets.
(f) To remove retired assets.

WEST TEXAS GAS UTILITY, LLC | **Schedule C-2**
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ACCUMULATED DEPRECIATION

Acct. No.	Description	12/31/2023 WTGU Total (a)	Oklahoma Direct (a)	Oklahoma Allocated (b)	Texas	Adjustments	Ref.	Adjusted Texas
	Production and Gathering Plant							
301.0	Organization	57,872	-	-	57,872			57,872
302.0	Franchises and Consents	200,000	-	-	200,000			200,000
303.0	Intangible Plant	5,964,243	(1,487,753)	(51,790)	4,424,701	(3,798,361)	(c)	626,340
332.0	Field Lines	3,395,407	-	-	3,395,407			3,395,407
334.0	Field M&R Station Equipment	50,485	-	-	50,485			50,485
								-
	Transmission Plant							-
365.0	Land and Rights-of-Way	612,078	-	-	612,078			612,078
366.0	Structures and Improvements	29,710	-	-	29,710	(29,710)	(d)	-
367.0	Mains	13,446,425	-	1	13,446,426			13,446,426
368.0	Compressor Station Equipment	49,512	-	-	49,512			49,512
369.0	M&R Station Equipment	770,132	-	-	770,132	29,710	(d)	799,842
371.0	Other Equipment	211,423	-	(1,028)	210,395			210,395
								-
	Distribution Plant							-
376.0	Mains	46,385,879	(5,200,615)	(1,900)	41,183,364			41,183,364
377.0	Compressors	390,830	(770)	-	390,060			390,060
378.0	M&R Station Equipment - General	5,369,708	(432,734)	(435)	4,936,538			4,936,538
387.0	Other Equipment	619,581	(68,674)	(2,844)	548,063			548,063
								-
	General Plant							-
389.0	Rights-of-Way	2,566,501	-	-	2,566,501			2,566,501
389.1	Land	-	-	-	-			-
390.0	Office Buildings	1,433,449	(54,836)	-	1,378,613			1,378,613
391.0	Office Furniture and Equipment	240,467	(22,771)	(6,228)	211,469	(138,779)	(e)	72,690
392.0	Transportation Equip	3,690,232	(695,100)	(26,306)	2,968,826	(1,773,863)	(d)(e)	1,194,963
394.0	Tools, Shop & Garage	892,166	(32,860)	(3,759)	855,547	(150,320)	(d)(e)	705,227
396.0	Power Operated Equipment	-	-	-	-	296,313	(d)	296,313
397.0	Communication Equip	316,334	-	(11,494)	304,840	(72,509)	(e)	232,331
398.0	Miscellaneous Equip	497,733	(310,911)	(414)	186,408	(149,381)	(d)(e)	37,027
	Accumulated Depreciation	**87,190,168**	**(8,307,025)**	**(106,196)**	**87,190,168**	**(5,786,900)**		**72,990,047**

(a) From WTGU books and records.
(b) Allocation of accumulated depreciation on corporate general plant to Oklahoma:

		Corporate	Oklahoma
	Oklahoma Plant as % of Total		6.52%
303.0	Intangible Plant	793,950	51,790
367.0	Mains	(12)	(1)
371.0	Other Equipment	15,757	1,028
376.0	Mains	29,122	1,900
378.0	M&R Station Equipment - General	6,669	435
387.0	Other Equipment	43,592	2,844
389.1	Land	-	-
391.0	Office Furniture and Equipment	95,473	6,228
392.0	Transportation Equip	403,275	26,306
394.0	Tools, Shop & Garage	57,625	3,759
397.0	Communication Equip	176,214	11,494
398.0	Miscellaneous Equip	6,353	414
	Total	1,628,019	106,196

(c) To remove accumulated amortization of acquisition adjustments.
(d) To reclassify assets.
(e) To remove retired assets.

WEST TEXAS GAS UTILITY, LLC | **Schedule C-3**
Test Period Ending December 31, 2023 | **Page 1 of 1**

MATERIALS AND SUPPLIES INVENTORY

Description	WTG Total (a)	Oklahoma (b)	Texas
Allocation percentage		**9.18%**	
Account No. 165 -- Prepayments:			
January	1,365,961	(125,400)	1,240,561
February	1,366,368	(125,437)	1,240,931
March	1,313,322	(120,567)	1,192,755
April	1,401,227	(128,637)	1,272,590
May	1,931,367	(177,306)	1,754,061
June	1,687,325	(154,902)	1,532,423
July	1,026,346	(94,222)	932,124
August	1,057,980	(97,126)	960,854
September	1,116,535	(102,502)	1,014,033
October	1,132,296	(103,948)	1,028,348
November	1,195,906	(109,788)	1,086,118
December	**1,016,495**	**(93,318)**	923,177
Average			**1,181,498**
Account No. 154 -- Materials & Supplies Inventory:			
January	2,053,134	(188,484)	1,864,650
February	2,098,706	(192,668)	1,906,038
March	2,078,249	(190,790)	1,887,459
April	2,079,755	(190,928)	1,888,827
May	2,045,937	(187,824)	1,858,114
June	2,074,860	(190,479)	1,884,381
July	2,056,089	(188,756)	1,867,333
August	2,052,299	(188,408)	1,863,891
September	1,999,842	(183,592)	1,816,250
October	1,999,798	(183,588)	1,816,210
November	1,963,296	(180,237)	1,783,059
December	**1,963,405**	**(180,247)**	1,783,158
Average			**1,851,614**

(a) From WTG books and records.
(b) Composite Corporate Allocation Factor (Schedule B-4).

WEST TEXAS GAS UTILITY, LLC **Schedule C-4**
Test Period Ending December 31, 2023 **Page 1 of 1**

EXCESS ACCUMULATED DEFERRED INCOME TAXES (a)

Total Net Plant in Service -- December 31, 2017	140,852,236	
Net Tax Basis of Total Plant in Service -- December 31, 2017	25,432,543	
Timing Difference		115,419,693
Reduction in Corporate Income Tax Rate (35% -21%)		14%
Excess ADIT Liability -- December 31, 2017		**16,158,757**
Adjusted Texas Plant in Service -- December 31, 2017	162,118,443	
Total Plant in Service -- December 31, 2017	198,183,147	
Percent Applicable to Texas		81.80%
Texas Excess ADIT Liability		**13,218,241**
Texas Contributions in Aid of Construction -- December 31, 2017	9,869,155	
Reduction in Corporate Income Tax Rate (35% -21%)	14%	
Texas Excess ADIT Asset -- December 31, 2017		1,381,682
Net Texas Excess ADIT Liability -- December 31, 2017		**11,836,559**
Total Texas Net Plant in Service -- December 31, 2017	117,497,855	
Depreciation Expense on 2017 Year-end Texas Assets	4,177,538	
Remaining Life of Assets (years)		28.1
Ratable Amortization of Excess ADIT Liabiility		**420,839**
Net Texas Excess ADIT Liability -- December 31, 2017	11,836,559	
Ratable Amortization:		
2018	(420,839)	
2019	(420,839)	
2020	(420,839)	
2021	(420,839)	
2022	(420,839)	
2023	(420,839)	
Excess ADIT at December 31, 2023		**9,311,525**

(a) From WTG books and records.

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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GAS RELIABILITY INFRASTRUCTURE PROGRAM ADDITIONS

		Amounts (a) Account	Total
January 1, 2020 - December 2020			
367.0	Mains	6,381,891	
369.0	M&R Station Equipment	11,106	
369.1	Meters	-	
376.0	Mains	11,201,810	
378.0	M&R Station Equipment - General	184,221	
387.0	Other Equipment	-	
390.0	Office Buildings	113,047	
391.0	Office Furniture and Equipment	2,596	
392.0	Transportation Equip	663,229	
394.0	Tools, Shop & Garage	57,576	
397.0	Communication Equip	42,766	
398.0	Miscellaneous Equip	10,499	
	Total		**18,668,741**
January 1, 2021 - December 2021			
367.0	Mains	14,575	
369.0	M&R Station Equipment	13,872	
369.1	Meters	3,828	
376.0	Mains	9,874,244	
378.0	M&R Station Equipment - General	123,182	
387.0	Other Equipment	3,765	
390.0	Office Buildings	-	
391.0	Office Furniture and Equipment	21,380	
392.0	Transportation Equip	607,217	
394.0	Tools, Shop & Garage	100,916	
397.0	Communication Equip	4,098	
398.0	Miscellaneous Equip	24,652	
	Total		**10,791,728**

		Amounts (a) Account	Total
January 1, 2022 - December 2022			
367.0	Mains	917,681	
369.0	M&R Station Equipment	54,113	
369.1	Meters	-	
376.0	Mains	13,106,529	
378.0	M&R Station Equipment - General	609,664	
387.0	Other Equipment	17,947	
390.0	Office Buildings	39,080	
391.0	Office Furniture and Equipment	4,292	
392.0	Transportation Equip	385,046	
394.0	Tools, Shop & Garage	76,615	
397.0	Communication Equip	14,329	
398.0	Miscellaneous Equip	69,771	
	Total		**15,295,068**
January 1, 2023 - December 2023			
367.0	Mains	130,064	
369.0	M&R Station Equipment	-	
369.1	Meters	8,760	
376.0	Mains	14,560,760	
378.0	M&R Station Equipment - General	868,969	
387.0	Other Equipment	6,518	
390.0	Office Buildings	7,473	
391.0	Office Furniture and Equipment	-	
392.0	Transportation Equip	-	
394.0	Tools, Shop & Garage	81,483	
397.0	Communication Equip	18,201	
398.0	Miscellaneous Equip	-	
	Total		**15,682,229**

(a) WTG books and records (detail is contained in electronic workpapers provided separately).

WEST TEXAS GAS UTILITY, LLC | **Schedule D**
Test Period Ending December 31, 2023 | **Page 1 of 1**

DEPRECIATION EXPENSE

Acct. No.	Description	2023 Texas Total (a)	Adjusted Texas Plant (b)	Current Depreciation Rates Rate (c)	Current Depreciation Rates Depreciation	Proposed Depreciation Rates Rate (d)	Proposed Depreciation Rates Depreciation
	Production and Gathering Plant						
301.0	Organization	57,872	57,872		-		-
302.0	Franchises and Consents	200,000	200,000		-		-
303.0	Intangible Plant	20,963,064	341,866		-		-
332.0	Field Lines	3,048,811	3,047,811		-		-
334.0	Field M&R Station Equipment	100,000	100,000		-		-
	Transmission Plant						
365.0	Land and Rights-of-Way	5,379,123	5,379,123	2.211%	118,936	2.160%	116,171
366.0	Structures and Improvements	149,596	-	2.642%			-
367.0	Mains	45,312,827	45,312,827	2.541%	1,151,558	2.219%	1,005,482
368.0	Compressor Station Equipment	38,984	38,984		-	2.484%	968
369.0	M&R Station Equipment	1,263,865	1,413,460	2.594%	36,661	2.432%	34,372
371.0	Other Equipment	224,148	224,148	4.847%	10,865	3.830%	8,585
	Distribution Plant						
376.0	Mains	167,899,665	167,899,665	2.606%	4,376,001	2.303%	3,866,825
377.0	Compressors	358,216	358,216				-
378.0	M&R Station Equipment - General	7,692,969	7,692,969	2.610%	200,817	2.412%	185,574
387.0	Other Equipment	687,636	687,636	3.813%	26,218	3.129%	21,513
	General Plant						
389.0	Rights-of-Way	6,308,629	6,308,629	2.009%	126,754	1.818%	114,718
389.1	Land	1,482,882	190,882				-
390.0	Office Buildings	4,562,846	4,562,846	4.243%	193,603	2.726%	124,373
391.0	Office Furniture and Equipment	421,526	272,377	6.434%	17,524	5.000%	13,619
392.0	Transportation Equip	4,101,836	2,900,187	10.658%	309,113	10.460%	303,356
394.0	Tools, Shop & Garage	1,394,965	1,162,584	4.000%	46,503	4.000%	46,503
396.0	Power Operated Equipment	-	356,492			4.301%	15,334
397.0	Communication Equip	577,490	523,132	6.667%	34,875	8.333%	43,594
398.0	Miscellaneous Equip	251,234	134,907	6.667%	8,994	6.667%	8,994
	Contributions in Aid of Construction (a)						
332.0	Field Lines	(272,521)	(272,521)	2.220%	(6,050)	2.220%	(6,050)
367.0	Mains	(1,909,128)	(1,909,128)	2.541%	(48,518)	2.219%	(42,363)
376.0	Mains	(28,246,138)	(28,246,138)	2.606%	(736,184)	2.303%	(650,525)
	Totals	**242,050,394**	**218,738,825**	**2.683%**	**5,867,672**	**2.382%**	
	Depreciation Expense						**5,211,043**

(a) WTG books and records (detail is contained in electronic workpapers provided separately).
(b) Schedule C-1.
(c) GUD No. 10998.
(d) Direct Testimony of Dane A. Watson.

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

RATE OF RETURN

Description (a)	Percent	Component Cost	Weighted Cost
Debt	34.40%	3.06%	1.05%
Equity	65.60%	10.75%	7.05%
Total	**100.00%**		
OVERALL RATE OF RETURN			**8.10%**

(a) Direct Testimony of Bruce H. Fairchild.

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

Schedule F
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INCOME TAX EXPENSE

Description	Reference	Amount	
Return on Investment:			
Rate Base	Schedule C	119,850,523	
Rate of Return	Schedule E	8.10%	
Return on Investment			**9,713,453**
Interest Expense:			
Rate Base	Schedule C	119,850,523	
Weighted Cost of Debt	Schedule E	1.05%	
Interest Expense			**(1,261,595)**
Return on Equity			**8,451,859**
Amortization of Excess ADIT	Schedule C-4		(420,839)
Adjusted Return on Equity			**8,031,020**
Income Tax Factor	(1+ (21%/(1 - 21%)))		1.2658
Taxable Income			**10,165,848**
Federal Corporate Income Tax Rate			21.00%
Income Tax Expense			**2,134,828**
Amortization of Excess ADIT	Schedule C-4		(420,839)
Net Income Tax Expense			**1,713,989**

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

Schedule G
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OTHER GAS INCOME BY MONTH (a)

Acct. No.	Description	January 2023	February	March	April	May	June	July	August	September	October	November	December	Total
488.0	Service Charges	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175	7,175	86,100
488.0	Connection Fees	15,200	18,222	20,475	21,990	17,250	11,640	12,050	16,360	18,314	24,190	17,915	15,930	209,536
488.0	Meter Repaid -- Labor	-	-	-	-	-	-	-	-	-	-	-	661,907	661,907
488.0	Sales -- Regulators, etc.	-	166	-	-	33,925	175	35	2,960	30,057	44	36,502	38,226	142,090
488.0	Returned Check Fees	1,100	1,450	1,350	1,175	175	1,000	1,200	650	1,050	1,275	1,225	1,825	13,475
488.0	Miscellaneous Tariff Fees	820	790	1,620	790	850	3,260	680	1,220	610	610	830	580	12,660
488.0	Collection Fees	-	-	-	-	-	-	-	-	-	-	-	-	-
492.0	Drip and Condensate Sal	27,760	25,343	22,238	2,793	4,515	3,514	4,196	3,826	24,699	-	-	(55,324)	63,560
495.0	Other Income	32,020	31,476	31,650	2,140	2,214	2,001	2,238	-	-	-	-	-	103,738
495.0	Purchase Meters	-	-	-	-	-	-	-	-	-	-	-	-	-

(a) WTG books and records.

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

OTHER GAS INCOME

Acct. No.	Description	Test Year WTG Total (a)	Oklahoma Direct (b)	Oklahoma Allocated (c)	Texas	Adjustments	Ref.	Adjusted Texas
488.0	Service Charges	86,100		(14,051)	72,049	-		72,049
488.0	Connection Fees	209,536	(20,779)	-	188,757	-		188,757
488.0	Meter Repairs -- Labor	661,907		(108,019)	553,888	-		553,888
488.0	Sales -- Regulators, etc.	142,090	(3)	(23,188)	118,899	-		118,899
488.0	Returned Check Fees	13,475	(1,518)	-	11,957	-		11,957
488.0	Miscellaneous Tariff Fees	12,660	(116)	-	12,544	-		12,544
488.0	Collection Fees	-	(1)	-	(1)	-		(1)
		-			-	-		
492.0	Drip and Condensate Sales	63,560	(12,866)	(8,273)	42,420	-		42,420
		-			-	-		
495.0	Other Income	103,738	-	(16,929)	86,809	-		86,809
495.0	Purchase Meters	-	-	-	-	-		-
	Totals	**1,293,066**	**(35,282)**	**(170,460)**	**1,087,324**			
	Other Gas Income							**1,087,324**

(a) Schedule G.
(b) WTG books and records (detail is contained in electronic workpapers provided separately).
(c) Allocated using Average Number of Customers Allocation Factor from Schedule B-4 of 16.32%

WEST TEXAS GAS UTILITY, LLC **Schedule H-1**
Test Period Ending December 31, 2023 **Page 1 of 1**

PAYROLL SUMMARY

WTG Direct Expense

Period	Regular Payroll	Overtime Pay	Holiday Pay	On Call Pay	PTO Pay	Total WTG Payroll	Number of Employees
Jan 2020- Dec 2020	N/A	N/A	N/A		N/A	6,801,295	N/A
Jan 2021- Dec 2021	N/A	N/A	N/A		N/A	7,489,540	N/A
Jan 2022- Dec 2022	N/A	N/A	N/A		N/A	7,784,222	150
Jan-23	455,549	42,318	52,887	372	48,943	600,069	134
Feb-23	514,920	71,783	27,377	423	22,950	637,453	133
Mar-23	759,085	124,404	26,770	379	41,193	951,831	134
Apr-23	500,587	72,430	26,436	115	30,689	630,256	136
May-23	518,777	84,807	-	287	27,773	631,645	134
Jun-23	495,035	72,229	26,953	194	35,524	629,934	133
Jul-23	499,268	93,609	26,817	91	42,352	662,137	134
Aug-23	770,895	133,806	-	323	61,354	966,379	134
Sep-23	505,930	74,568	27,338	97	34,094	642,027	135
Oct-23	518,112	92,009	-	177	37,243	647,541	135
Nov-23	515,507	91,329	-	162	39,938	646,935	137
Dec-23	456,475	62,671	54,440	275	50,628	624,489	136
Total	6,510,140	1,015,964	269,017	2,894	472,681	8,270,696	135

WTG Allocated Expense through WTGDS

Period	Regular Payroll	Overtime Pay	Holiday Pay	On Call Pay	PTO Pay	Total WTG Payroll	Number of Employees
Jan 2020- Dec 2020	N/A	N/A	N/A	N/A	N/A	1,238,849	N/A
Jan 2021- Dec 2021	N/A	N/A	N/A	N/A	N/A	1,322,933	N/A
Jan 2022- Dec 2022	N/A	N/A	N/A	N/A	N/A	1,109,243	N/A
Jan-23	62,239	4	N/A	N/A	N/A	62,243.4	9
Feb-23	62,895	1,097	N/A	N/A	N/A	63,991.5	8
Mar-23	97,188	1,660	N/A	N/A	N/A	98,847.6	8
Apr-23	66,207	32	N/A	N/A	N/A	66,238.4	8
May-23	65,613	1,053	N/A	N/A	N/A	66,666.6	8
Jun-23	66,001	861	N/A	N/A	N/A	66,862.1	8
Jul-23	65,953	616	N/A	N/A	N/A	66,569.6	8
Aug-23	104,509	1,874	N/A	N/A	N/A	106,383.7	11
Sep-23	66,142	1,039	N/A	N/A	N/A	67,180.5	12
Oct-23	69,344	917	N/A	N/A	N/A	70,261.8	12
Nov-23	69,219	658	N/A	N/A	N/A	69,877.0	12
Dec-23	69,561	322	N/A	N/A	N/A	69,882.3	12
Total	864,871	10,134	N/A	N/A	N/A	875,004.5	10

WEST TEXAS GAS UTILITY, LLC **Schedule H-2**
Test Period Ending December 31, 2023 **Page 1 of 1**

PAYROLL ANALYSIS

Period	Total WTG Payroll	Total Expensed	Total Capitalized	Charged to Clearing Accounts
Jan 2020- Dec 2020	6,351,681	8,040,144	(1,688,462)	-
Jan 2021- Dec 2021	7,696,602	8,812,472	(1,115,870)	
Jan 2022- Dec 2022	7,432,162	8,893,465	(1,461,302)	
Jan-23	662,313	662,313	-	
Feb-23	701,445	701,445	-	
Mar-23	1,050,679	1,050,679	-	
Apr-23	696,495	696,495	-	
May-23	698,311	698,311	-	
Jun-23	696,796	696,796	-	
Jul-23	728,706	728,706	-	
Aug-23	1,072,762	1,072,762	-	
Sep-23	709,208	709,208	-	
Oct-23	717,803	717,803	-	
Nov-23	716,812	716,812	-	
Dec-23	(536,004)	694,371	(1,230,375)	
Total	7,915,325	9,145,700	(1,230,375)	

WEST TEXAS GAS UTILITY, LLC **Schedule H-3**
Test Period Ending December 31, 2023 **Page 1 of 1**

BAD DEBTS

West Texas Gas subscribes to the following procedures for the write-off of bad debts:

Efforts to collect past due accounts are first made by the local district office and credit manager for West Texas Gas. If internal efforts to collect the account are unsuccessful, it is then turned over for collection to an outside collection agency or an attorney. If those efforts are unsuccessful, then based on the recommendation of the credit manager or responsible attorney, the account balance is written off to the reserve for bad debt account.

West Texas Gas records a monthly accrual to its Reserve for Bad Debt account using the following method:

During the period January 2023 - December 2023:
Current Month NG Sales Revenue X .125% = Reserve Accrual

Period	Reserve Balance at Beginning of Month	Bad Debt Monthly Accrual	Payments Collected on Bad Debt Accounts	Amounts Written Off	Reserve Balance at End of Month
Jan 2020- Dec 2020	1,899,156	124,885	1,550	(141,442)	1,884,148
Jan 2021- Dec 2021	1,884,148	196,292	2,862	-	2,083,302
Jan 2022- Dec 2022	2,083,302	343,111	2,712	(82,895)	2,346,230
Jan-23	2,346,230	20,875	433	-	2,367,538
Feb-23	2,367,538	13,820	523	-	2,381,881
Mar-23	2,381,881	16,046	481	-	2,398,408
Apr-23	2,398,408	16,293	95	-	2,414,795
May-23	2,414,795	13,034	89	-	2,427,918
Jun-23	2,427,918	8,956	107	-	2,436,981
Jul-23	2,436,981	17,800	428	-	2,455,209
Aug-23	2,455,209	23,506		-	2,478,715
Sep-23	2,478,715	16,814	16	-	2,495,545
Oct-23	2,495,545	11,853	542	-	2,507,940
Nov-23	2,507,940	11,174	399	-	2,519,514
Dec-23	2,519,514	10,441	147	(1,260,310)	1,269,792
Total		119,027	5,130	(123,396)	

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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ADVERTISING EXPENSES

		Region									
Period	**FERC Acct**	**Corp R-1**	**R-10**	**R-20**	**R-30**	**R-40**	**R-50**	**R-60**	**R-70**	**R-80**	**Total**
Jan-23	913.0	-	-	-	-	-	79	800	-		879
Feb-23	913.0	-	-	-	-	-	79	-	-	6,305	6,384
Mar-23	913.0	-	-	762	-	60	-	-	-	860	1,682
Apr-23	913.0	-	-	685	-	-	-	1,380	130		2,195
May-23	913.0	-	-	1,262	-	-	-	281	-		1,543
Jun-23	913.0	-	-	-	-	125	79	954	-	938	2,096
Jul-23	913.0	-	-	5	-	-	79		-		84
Aug-23	913.0	-	-	-	23	47	79	447	-	629	1,225
Sep-23	913.0	-	150	-	-	63	-	1,574	-		1,787
Oct-23	913.0	-	799	467	-	-	79	799	-		2,144
Nov-23	913.0	-	-	-	-	-	-	-	-	-	-
Dec-23	913.0	-	799	-	75	140	150	-	210	-	1,374
Total		**-**	**1,748**	**3,181**	**98**	**435**	**624**	**6,234**	**340**	**8,732**	**21,392**

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

DONATIONS AND CONTRIBUTIONS

		Region										
Payee	**FERC Acct.**	**Corp R-1**	**R-10**	**R-20**	**R-30**	**R-40**	**R-50**	**R-60**	**R-70**	**R-80**	**Total**	**Purpose**
S.M.A.R.T.	880.0	-	-	-	-	-	-	-	50	-	50	Donation/Sponsorship
DALHART FIRE DEPARTMENT	880.0	-	-	-	-	-	-	200	-	-	200	Donation/Sponsorship
DHS YEARBOOK	880.0	-	-	-	-	-	-	200	-	-	200	Donation/Sponsorship
DALHART PROJECT GRADUATION	880.0	-	-	-	-	-	-	250	-	-	250	Donation/Sponsorship
LUBBOCK LEMONADE DAY	880.0	-	-	500	-	-	-	-	-	-	500	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	-	-	-	-	1,750	1,750	Donation/Sponsorship
HIGGINBOTHAM BUILDING CENTER	880.0	-	-	-	368	-	-	-	-	-	368	Donation/Sponsorship
ETA UPSILON SORORITY	880.0	-	-	-	-	-	-	100	-	-	100	Donation/Sponsorship
TEXAS GAS ASSOCIATION	880.0	-	350	-	-	-	-	-	-	-	350	Donation/Sponsorship
AARON K BOLES	880.0	-	-	251	-	-	-	-	-	-	251	Donation/Sponsorship
CANADIAN ROTARY CLUB	880.0	-	-	-	-	60	-	-	-	-	60	Donation/Sponsorship
BI-COUNTY FIRST RESPONDERS	880.0	-	-	-	-	-	-	320	-	-	320	Donation/Sponsorship
USA LLC	880.0	-	799	-	-	-	-	-	-	-	799	Donation/Sponsorship
JUNCTION ROTARY CLUB	880.0	-	-	-	95	-	-	-	-	-	95	Donation/Sponsorship
THE DALHART TEXAN	880.0	-	-	-	-	400	-	-	-	-	400	Donation/Sponsorship
KIMBLE CO. CHAMBER OF COMMERCE	880.0	-	-	-	125	-	-	-	-	-	125	Donation/Sponsorship
WHEELER LIONS CLUB	880.0	-	-	-	-	35	-	-	-	-	35	Donation/Sponsorship
FIVE RIVERS-CIMARRON FEEDER'S	880.0	-	-	-	-	-	-	650	-	-	650	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	-	-	500	-	-	500	Donation/Sponsorship
XIT RODEO AND REUNION	880.0	-	-	-	-	-	-	6,000	-	-	6,000	Donation/Sponsorship
ONSHORE QUALITY CONTROL	880.0	-	500	-	-	-	-	-	-	-	500	Donation/Sponsorship
OUR LADY OF FATIMA CATHOLIC	880.0	-	500	-	-	-	-	-	-	-	500	Donation/Sponsorship
SHAMROCK ROTARY CLUB	880.0	-	-	-	-	30	-	-	-	-	30	Donation/Sponsorship
DALHART GOLDEN WOLVES BAND	880.0	-	-	-	-	-	-	250	-	-	250	Donation/Sponsorship
ONSHORE QUALITY CONTROL	880.0	-	(500)	-	-	-	-	-	-	-	(500)	Donation/Sponsorship
MOORE COUNTY CHAMBER OF	880.0	-	-	-	-	-	-	250	-	-	250	Donation/Sponsorship
KERMIT ROTARY CLUB	880.0	-	75	-	-	-	-	-	-	-	75	Donation/Sponsorship
USA LLC	880.0	-	799	-	-	-	-	-	-	-	799	Donation/Sponsorship
STRIKE OUT CANCER	880.0	-	-	-	-	-	-	300	-	-	300	Donation/Sponsorship
CANADIAN RIVER BEACH CLUB, INC	880.0	-	-	-	-	5,000	-	-	-	-	5,000	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	-	-	1,525	-	-	1,525	Donation/Sponsorship
CANADIAN RIVER BEACH CLUB, INC	880.0	-	-	-	-	5,000	-	-	-	-	5,000	Donation/Sponsorship
MINDY LEE	880.0	-	-	-	-	-	-	-	200	-	200	Donation/Sponsorship
STEPHANIE FOUST	880.0	-	-	-	-	-	-	350	-	-	350	Donation/Sponsorship
DEVINE YOUTH SPORTS INC	880.0	-	-	-	-	-	-	-	-	250	250	Donation/Sponsorship
GROOM LIONS CLUB	880.0	-	-	-	-	-	25	-	-	-	25	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	(5,000)	-	-	-	-	(5,000)	Donation/Sponsorship
ARMSTRONG COUNTY JR LIVESTOCK	880.0	-	-	-	-	-	500	-	-	-	500	Donation/Sponsorship
CANYON INDEPENDENT SCHOOL	880.0	-	-	-	-	-	500	-	-	-	500	Donation/Sponsorship
RICKY RICE	880.0	-	-	-	-	-	-	375	-	-	375	Donation/Sponsorship
SHAMROCK FIRE DEPARTMENT	880.0	-	-	-	-	250	-	-	-	-	250	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	-	-	318	-	-	318	Donation/Sponsorship
SHAMROCK JR. LIVESTOCK	880.0	-	-	-	-	250	-	-	-	-	250	Donation/Sponsorship
HEMPHILL COUNTY LIVESTOCK	880.0	-	-	-	-	250	-	-	-	-	250	Donation/Sponsorship
WEST TEXAS A&M UNIVERSITY	880.0	-	-	-	-	-	875	-	-	-	875	Donation/Sponsorship
WEST TEXAS GAS UTILITY, LLC	880.0	-	-	-	-	-	-	495	-	-	495	Donation/Sponsorship
NATURAL GAS SOCIETY OF THE P.B	930.2	1,000	-	-	-	-	-	-	-	-	1,000	Donation/Sponsorship
MIDLAND RAPE CRISIS CENTER INC	930.2	3,500	-	-	-	-	-	-	-	-	3,500	Donation/Sponsorship
CENTERS FOR CHILDREN &	930.2	5,000	-	-	-	-	-	-	-	-	5,000	Donation/Sponsorship
TEXAS COTTON GINNERS'	930.2	850	-	-	-	-	-	-	-	-	850	Donation/Sponsorship
TEXAS COTTON GINNERS'	930.2	850	-	-	-	-	-	-	-	-	850	Donation/Sponsorship
ROTARY CLUB OF MIDLAND	930.2	500	-	-	-	-	-	-	-	-	500	Donation/Sponsorship
TOTAL		**11,700**	**2,523**	**751**	**588**	**6,275**	**1,900**	**12,083**	**250**	**2,000**	**38,070**	

WEST TEXAS GAS UTILITY, LLC
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LOBBYING EXPENSES

Month	Payee	Account Charged	Amount	Purpose
Jan-23	Phil Gamble Attorney At Law	923.0	814	Professional Services
Feb-23	Phil Gamble Attorney At Law	923.0	822	Professional Services
Mar-23	Phil Gamble Attorney At Law	923.0	814	Professional Services
Apr-23	Phil Gamble Attorney At Law	923.0	814	Professional Services
May-23	Phil Gamble Attorney At Law	923.0	814	Professional Services
Jun-23	Phil Gamble Attorney At Law	923.0	875	Professional Services
Jul-23	Phil Gamble Attorney At Law	923.0	875	Professional Services
Aug-23	Phil Gamble Attorney At Law	923.0	875	Professional Services
Sep-23	Phil Gamble Attorney At Law	923.0	883	Professional Services
Oct-23	Phil Gamble Attorney At Law	923.0	875	Professional Services
Nov-23	Phil Gamble Attorney At Law	923.0	883	Professional Services
Dec-23	Phil Gamble Attorney At Law	923.0	875	Professional Services
Total			**10,219**	

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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PENALTIES AND FINES

Month	Payee	Account Charged	Amount	Purpose
Jan-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 077804
May-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 079597
Jun-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 079923
Jul-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 080575
Jul-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 080284
Jul-23	RAILROAD COMMISSION OF TX	921.0	3,500	DOC NO 080665
Jul-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 081223
Aug-23	COMPTROLLER OF PUBLIC ACCOUNTS	921.0	367	EFT PENALTY
Aug-23	RAILROAD COMMISSION OF TX	921.0	2,750	DOC NO 080284
Dec-23	RAILROAD COMMISSION OF TX	921.0	2,500	DOC NO 083953
Total			**24,117**	

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

OUTSIDE SERVICES CHARGED TO A&G ACCOUNTS

Month	Payee	Account Charged	Amount	Purpose
Jan-24	ZDSCADA LP	923.0	53	Scada Hosting Services
Jan-24	ASSOCIATED SYSTEMS	923.0	2,264	Billing Software Support
Jan-24	JOE COFFMAN	923.0	6,374	Consulting
Jan-24	COST CONTAINMENT ADVISORS, INC	923.0	33,976	Consulting
Jan-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,168	Contract Labor
Jan-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,460	Contract Labor
Jan-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,460	Contract Labor
Jan-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,140	Contract Labor
Jan-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,460	Contract Labor
Jan-24	WTG DOWNSTREAM SERVICES LLC	923.0	66,595	Overhead
Jan-24	RCP INC	923.0	905	Regulatory Compliance
Jan-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	50	Safety Services
Jan-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,142	Safety Services
Jan-24	OLEN DOUGLASS	923.0	(58)	Contract Labor
Feb-24	WHITLEY PENN LLP	923.0	1,301	Accounting
Feb-24	ASSOCIATED SYSTEMS	923.0	2,553	Billing Software Support
Feb-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,460	Contract Labor
Feb-24	ROBERT HALF INTERNATIONAL INC.	923.0	1,460	Contract Labor
Feb-24	WTG DOWNSTREAM SERVICES LLC	923.0	46,328	Overhead
Feb-24	RCP INC	923.0	505	Regulatory Compliance
Feb-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,165	Safety Services
Mar-24	WHITLEY PENN LLP	923.0	3,014	Accounting
Mar-24	ALWAYS ANSWER	923.0	2,849	Answering Service
Mar-24	ASSOCIATED SYSTEMS	923.0	4,368	Billing Software Support
Mar-24	WTG DOWNSTREAM SERVICES LLC	923.0	72,999	Overhead
Mar-24	RCP INC	923.0	400	Regulatory Compliance
Mar-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,690	Safety Services
Apr-24	WHITLEY PENN LLP	923.0	56,963	Accounting
Apr-24	ALWAYS ANSWER	923.0	2,848	Answering Service
Apr-24	ASSOCIATED SYSTEMS	923.0	8,823	Billing Software Support
Apr-24	JOE COFFMAN	923.0	6,150	Consulting
Apr-24	ESRI, INC.	923.0	56,983	Mapping Software Support
Apr-24	WTG DOWNSTREAM SERVICES LLC	923.0	50,617	Overhead
Apr-24	RCP INC	923.0	400	Regulatory Compliance
Apr-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,399	Safety Services
May-24	ASSOCIATED SYSTEMS	923.0	6,224	Billing Software Support
May-24	JOE COFFMAN	923.0	5,557	Consulting
May-24	WTG DOWNSTREAM SERVICES LLC	923.0	67,129	Overhead
May-24	U S PAYMENTS LLC	923.0	1,547	Payment Software Support
May-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,418	Safety Services
May-24	ENTECH CONSULTING CORP	923.0	35,817	Consulting
May-24	ENERGY SERVICES GROUP	923.0	1,066	FERC Filing Support
Jun-24	U S PAYMENTS LLC	923.0	1,523	Payment Software Support
Jun-24	ALWAYS ANSWER	923.0	3,322	Answering Service
Jun-24	ASSOCIATED SYSTEMS	923.0	2,017	Billing Software Support
Jun-24	JOE COFFMAN	923.0	4,275	Consulting
Jun-24	DONALD G. BLAND	923.0	1,374	Contract Labor
Jun-24	WTG DOWNSTREAM SERVICES LLC	923.0	203,280	Overhead
Jun-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,228	Safety Services
Jul-24	WHITLEY PENN LLP	923.0	18,383	Accounting
Jul-24	ALWAYS ANSWER	923.0	2,406	Answering Service
Jul-24	ASSOCIATED SYSTEMS	923.0	4,657	Billing Software Support
Jul-24	JOE COFFMAN	923.0	6,675	Consulting
Jul-24	WTG DOWNSTREAM SERVICES LLC	923.0	90,732	Overhead
Jul-24	U S PAYMENTS LLC	923.0	1,368	Payment Software Support
Jul-24	U S PAYMENTS LLC	923.0	1,495	Payment Software Support
Jul-24	RCP INC	923.0	820	Regulatory Compliance
Jul-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,230	Safety Services
Jul-24	HI PLAINS CANVAS PRODUCTS INC.	923.0	490	Contract Labor
Jul-24	ENERGY SERVICES GROUP	923.0	3,998	FERC Filing Support
Jul-24	AERIANA ROJAS	923.0	525	Contract Labor
Aug-24	WHITLEY PENN LLP	923.0	16,034	Accounting
Aug-24	ASSOCIATED SYSTEMS	923.0	5,399	Billing Software Support
Aug-24	JOE COFFMAN	923.0	5,100	Consulting
Aug-24	WTG DOWNSTREAM SERVICES LLC	923.0	70,304	Overhead
Aug-24	RCP INC	923.0	610	Regulatory Compliance
Aug-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,567	Safety Services
Aug-24	PARADIGM ALLIANCE INC	923.0	15,054	Public Awareness Mailing Service
Aug-24	ALTAMIRA-US, LLC	923.0	40,396	ROW Assessment
Sep-24	WHITLEY PENN LLP	923.0	2,750	Accounting
Sep-24	ASSOCIATED SYSTEMS	923.0	8,740	Billing Software Support
Sep-24	JOE COFFMAN	923.0	6,450	Consulting
Sep-24	WILLIS PERMIAN MOVERS INC	923.0	100	Contract Labor
Sep-24	WILLIS PERMIAN MOVERS INC	923.0	581	Contract Labor
Sep-24	WTG DOWNSTREAM SERVICES LLC	923.0	45,194	Overhead
Sep-24	RCP INC	923.0	500	Regulatory Compliance
Sep-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,397	Safety Services
Oct-24	WHITLEY PENN LLP	923.0	1,410	Accounting
Oct-24	OKLAHOMA ONE-CALL SYSTEM INC	923.0	5,404	Answering Service
Oct-24	ASSOCIATED SYSTEMS	923.0	5,399	Billing Software Support
Oct-24	JOE COFFMAN	923.0	6,314	Consulting
Oct-24	WTG DOWNSTREAM SERVICES LLC	923.0	109,894	Overhead
Oct-24	RCP INC	923.0	715	Regulatory Compliance
Oct-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	3	Safety Services
Oct-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,317	Safety Services
Nov-24	WHITLEY PENN LLP	923.0	12,627	Accounting
Nov-24	ALWAYS ANSWER	923.0	3,043	Answering Service
Nov-24	ENTECH CONSULTING CORP	923.0	13,016	Consulting
Nov-24	WTG DOWNSTREAM SERVICES LLC	923.0	79,616	Overhead
Nov-24	RCP INC	923.0	400	Regulatory Compliance
Dec-24	WHITLEY PENN LLP	923.0	4,939	Accounting
Dec-24	ALWAYS ANSWER	923.0	3,000	Answering Service
Dec-24	ASSOCIATED SYSTEMS	923.0	2,924	Billing Software Support
Dec-24	AVATAR SYSTEMS INC	923.0	1,786	Billing Software Support
Dec-24	ASSOCIATED SYSTEMS	923.0	2,842	Billing Software Support
Dec-24	I.C. SYSTEMS, INC.	923.0	271	Collections
Dec-24	ENTECH CONSULTING CORP	923.0	55,000	Consulting
Dec-24	JOE COFFMAN	923.0	14,550	Consulting
Dec-24	WTG DOWNSTREAM SERVICES LLC	923.0	64,727	Overhead
Dec-24	RCP INC	923.0	400	Regulatory Compliance
Dec-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	2,034	Safety Services
Dec-24	TEXAS EXCAVATION SAFETY SYSTEM	923.0	1,636	Safety Services
Total			**1,534,259**	

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LEGAL EXPENSE DETAIL

			Region									
Line	**Payee**	**FERC Acct.**	**Corp R-1**	**R-10**	**R-20**	**R-30**	**R-40**	**R-50**	**R-60**	**R-70**	**R-80**	**Total**
1	TODD, BARRON, THOMASON,	923.0	(140)	-	-	-	-	-	-	-	-	(140)
2	ROSS MOLINA OLIVEROS PC	923.0	163	-	-	-	-	-	-	-	-	163
3	ROSS MOLINA OLIVEROS PC	923.0	163	-	-	-	-	-	-	-	-	163
4	TODD, BARRON, THOMASON,	923.0	38	-	-	-	-	-	-	-	-	38
5	COFFIN RENNER LLP	923.0	942	-	-	-	-	-	-	-	-	942
6	COFFIN RENNER LLP	923.0	6,005	-	-	-	-	-	-	-	-	6,005
7	JOHN & HENGERER LLP	923.0	8,700	-	-	-	-	-	-	-	-	8,700
8	COFFIN RENNER LLP	923.0	4,617	-	-	-	-	-	-	-	-	4,617
9	TODD, BARRON, THOMASON,	923.0	341	-	-	-	-	-	-	-	-	341
10	SMITH CLARK PLLC	923.0	6,111	-	-	-	-	-	-	-	-	6,111
11	COFFIN RENNER LLP	923.0	979	-	-	-	-	-	-	-	-	979
12	COFFIN RENNER LLP	923.0	6,140	-	-	-	-	-	-	-	-	6,140
13	SIDLEY AUSTIN LLP	923.0	7,251	-	-	-	-	-	-	-	-	7,251
14	TODD, BARRON, THOMASON,	923.0	36	-	-	-	-	-	-	-	-	36
15	TODD, BARRON, THOMASON,	923.0	591	-	-	-	-	-	-	-	-	591
16	SMITH CLARK PLLC	923.0	8,056	-	-	-	-	-	-	-	-	8,056
17	TODD, BARRON, THOMASON,	923.0	97	-	-	-	-	-	-	-	-	97
18	SMITH CLARK PLLC	923.0	15,372	-	-	-	-	-	-	-	-	15,372
19	COFFIN RENNER LLP	923.0	(4,617)	-	-	-	-	-	-	-	-	(4,617)
20	JOHN & HENGERER LLP	923.0	8,156	-	-	-	-	-	-	-	-	8,156
21	COFFIN RENNER LLP	923.0	4,108	-	-	-	-	-	-	-	-	4,108
22	TODD, BARRON, THOMASON,	923.0	51	-	-	-	-	-	-	-	-	51
23	TODD, BARRON, THOMASON,	923.0	33	-	-	-	-	-	-	-	-	33
24	SMITH CLARK PLLC	923.0	(3,297)	-	-	-	-	-	-	-	-	(3,297)
25	JOHN & HENGERER LLP	923.0	1,813	-	-	-	-	-	-	-	-	1,813
26	TODD, BARRON, THOMASON,	923.0	330	-	-	-	-	-	-	-	-	330
27	TODD, BARRON, THOMASON,	923.0	228	-	-	-	-	-	-	-	-	228
28	JOHN & HENGERER LLP	923.0	544	-	-	-	-	-	-	-	-	544
29	COFFIN RENNER LLP	923.0	206	-	-	-	-	-	-	-	-	206
30	COFFIN RENNER LLP	923.0	3,875	-	-	-	-	-	-	-	-	3,875
31	SMITH CLARK PLLC	923.0	6,814	-	-	-	-	-	-	-	-	6,814
32	COFFIN RENNER LLP	923.0	1,817	-	-	-	-	-	-	-	-	1,817
33	COFFIN RENNER LLP	923.0	11,809	-	-	-	-	-	-	-	-	11,809
34	G. WILLIAM FOWLER, P. C.	923.0	748	-	-	-	-	-	-	-	-	748
35	ROSS MOLINA OLIVEROS PC	923.0	390	-	-	-	-	-	-	-	-	390
36	COFFIN RENNER LLP	923.0	2,661	-	-	-	-	-	-	-	-	2,661
37	COFFIN RENNER LLP	923.0	3,438	-	-	-	-	-	-	-	-	3,438
38	COFFIN RENNER LLP	923.0	875	-	-	-	-	-	-	-	-	875
39	G. WILLIAM FOWLER, P. C.	923.0	417	-	-	-	-	-	-	-	-	417
40	SMITH CLARK PLLC	923.0	6,688	-	-	-	-	-	-	-	-	6,688
41	COTTON BLEDSOE TIGHE & DAWSON	923.0	350	-	-	-	-	-	-	-	-	350
42	JOHN & HENGERER LLP	923.0	1,631	-	-	-	-	-	-	-	-	1,631
43	COFFIN RENNER LLP	923.0	1,188	-	-	-	-	-	-	-	-	1,188
44	COFFIN RENNER LLP	923.0	2,476	-	-	-	-	-	-	-	-	2,476
45	DAVIS, GERALD & CREMER	923.0	1,330	-	-	-	-	-	-	-	-	1,330
46	COFFIN RENNER LLP	923.0	2,005	-	-	-	-	-	-	-	-	2,005
47	COFFIN RENNER LLP	923.0	1,500	-	-	-	-	-	-	-	-	1,500
48	DAVIS, GERALD & CREMER	923.0	1,376	-	-	-	-	-	-	-	-	1,376
49	SMITH CLARK PLLC	923.0	4,362	-	-	-	-	-	-	-	-	4,362
50	COFFIN RENNER LLP	874.0		1,688	-	-	-	-	-	-	-	1,688
51	**Total**		**128,759**	**1,688**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**130,447**

WEST TEXAS GAS UTILITY, LLC
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LOST AND UNACCOUNTED-FOR GAS

Period	Total Texas Receipts (Mcf)	Total Texas Deliveries (Mcf)	Distribution Gain / (Loss)	Distribution LUFG Percent
Jan 2020 - Dec 2020	28,516,710	27,270,221	(1,246,489)	-4.37%
Jan 2021 - Dec 2021	28,182,783	27,553,940	(628,843)	-2.23%
Jan 2022 - Dec 2022	31,262,353	30,296,943	(965,410)	-3.09%
Jan 2023 - Dec 2023	28,337,712	27,359,457	(978,255)	-3.45%

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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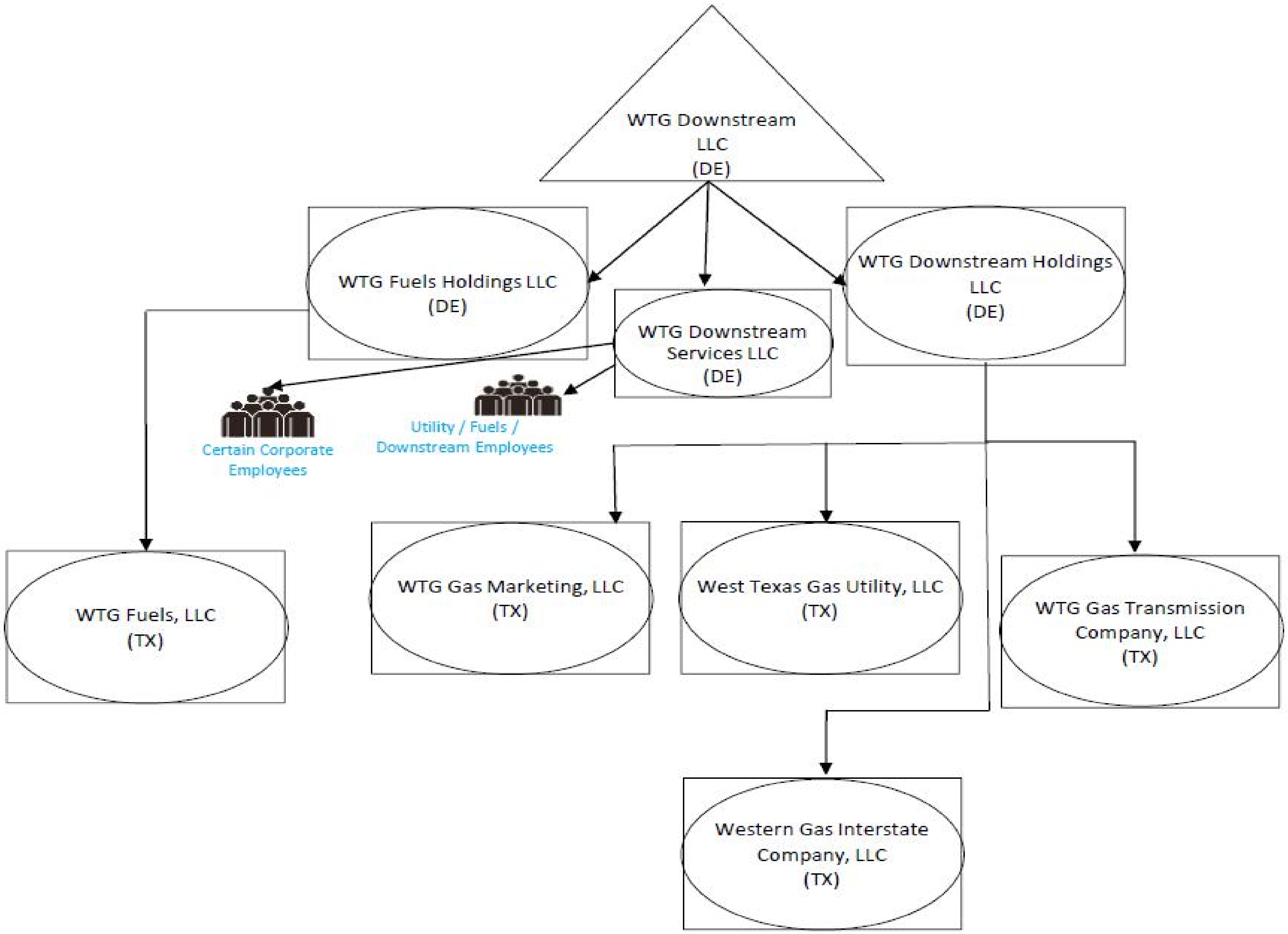
ORGANIZATIONAL CHART



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Test Period Ending December 31, 2023

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CHARGES BY AFFILIATES TO WTG

Affiliate	Nature of Charge	Amount (a) (b)	FERC #	Basis
WTG Gas Marketing, LLC	Gas Purchases	60,787,627	803.0	Cost Per Gas Purchase Contract with Affiliate
Total Gas Purchases		60,787,627		
Western Gas Interstate Company	Gas Transport	441,354	858.0	Cost per Gas Contract with Affiliate
Total Gas Transport		441,354		
WTG Fuels, Inc.	Auto Oil & Gas	358,393	930.2	Street price
WTG Fuels, Inc.	Auto Other	342	880.0	At cost
WTG Fuels, Inc.	Auto Maint	1,458	894.0	At cost
Total Auto Oil & Gas		360,193		
WTG Fuels, Inc.	Propane	2,488	880.0	At cost
Total Propane		2,488		
WTG Downstream Services, LLC	Overhead Burden	967,417	923.0	As calculated in Corp Allocation Formula
Total Overhead Burden		967,417		
Total		**62,559,079**		

(a) Gas Purchases and Gas Transport charges by affiliates excluded from calculation of base rates; all other charges by affiliates to WTG included.
(b) No charges by affiliates were capitalized during the test year.

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CHARGES BY AFFILIATES TO OTHERS

Line	Affiliate (Recording Income)	Nature of Charge	Affiliate (Recording Expense)	Amount
1	WTG Downstream Services LLC	Overhead Burden	WTG Fuels LLC	694,516
2	WTG Downstream Services LLC	Overhead Burden	WTG Gas Marketing LLC	236,022
3	WTG Downstream Services LLC	Overhead Burden	Western Gas Interstate Co LLC	60,241
4	WTG Downstream Services LLC	Overhead Burden	WTG South Permian - Irion County	158,770
5	WTG Downstream Services LLC	Overhead Burden	WTG Gas Processing LLC	273,854
6	WTG Downstream Services LLC	Overhead Burden	Fuller Gas Plant	30,220
7	WTG Downstream Services LLC	Overhead Burden	East Vealmoor Plant	1,645,567
8	WTG Downstream Services LLC	Overhead Burden	WTG North Permian Midstream LLC	2,917,286
9	WTG Downstream Services LLC	Overhead Burden	WTG Fuels LLC	10,527
10	WTG Downstream Services LLC	Overhead Burden	WTG Gas Transmission Company LLC	284,553
11	WTG Downstream Services LLC	Overhead Burden	WTG Jameson L.P.	578,325
12	WTG Downstream Services LLC	Overhead Burden	Ledco LLC	20,646
13	WTG Downstream Services LLC	Overhead Burden	WTG Hugoton L.P.	104,754
14	WTG Downstream Services LLC	Overhead Burden	WTG NGL Marketing LLC	100,431
15	WTG Downstream Services LLC	Overhead Burden	WTG Gas Gathering Company LLC	167,206
16	WTG Downstream Services LLC	Overhead Burden	WTG NGL Pipeline Company LLC	57,882
17	WTG Downstream Services LLC	Overhead Burden	WTG Midstream Marketing	42,597
18	WTG Downstream Services LLC	Overhead Burden	Low Country Power	74,390
19	WTG Downstream Services LLC	Overhead Burden	WTG South Permian Midstream LLC	2,727,297
20	WTG North Permian Midstream LLC	Gas Plant Product	WTG NGL Marketing LLC	6,865,918
21	WTG NGL Pipeline Company LLC	Gas Transportation	WTG Gas Processing Super System	1,786,109
22	WTG NGL Pipeline Company LLC	Gas Transportation	WTG NGL Marketing LLC	1,580,299
23	WTG NGL Pipeline Company LLC	Gas Transportation	WTG North Permian Midstream	204,601
24	WTG Midstream Marketing LLC	Natural Gas Purchases	WTG Gas Marketing LLC	74,003,473
25	WTG Midstream Marketing LLC	Natural Gas Purchases	WTG Gas Processing Super System	23,814,436
26	WTG Gas Transmission Company LLC	Gas Transportation	WTG Gas Marketing LLC	5,145,979
27	WTG Gas Transmission Company LLC	Gas Transportation	WTG Midstream Marketing	15,364,768
28	WTG Gas Processing LLC	Gas Transportation	Fuller Gas Plant	12,299
29	WTG Gas Processing LLC	Gas Plant Product	WTG NGL Marketing LLC	28,000,517
30	WTG Gas Processing LLC-Supersystem	Gas Transportation	WTG NGL Pipeline Company LLC	154,326
31	WTG Gas Processing LLC-Supersystem	Gas Plant Product	WTG NGL Marketing LLC	738,174,530
32	WTG Gas Processing LLC-Supersystem	Gas Plant Product	Low Country Power	4,541,681
33	WTG Gas Processing LLC-Supersystem	Gas Plant Product	WTG Gas MarketingLLC	564,149
34	WTG Gas Processing LLC-Supersystem	Gas Plant Product	WTG Midstream Marketing	360,188,268
35	WTG Gas Marketing LLC	Natural Gas Purchases	Fuller Gas Plant	6,226
36	WTG Gas Marketing LLC	Natural Gas Purchases	WTG Gas Processing Super System	16,307,341
37	WTG Gas Marketing LLC	Natural Gas Purchases	WTG Jameson L.P.	170,118
38	WTG Gas Marketing LLC	Natural Gas Purchases	WTG Midstream Marketing	7,014
39	WTG Gas Marketing LLC	Natural Gas Purchases	WTG South Permian Midstream LLC	1,382,242
40	WTG Gas Gathering Company LLC	Gas Transportation	WTG Gas Processing Super System	8,040,330
41	WTG Gas Gathering Company LLC	Gas Transportation	WTG South Permian - Irion County	147,460
42	WTG Gas Gathering Company LLC	Gas Transportation	WTG South Permian Midstream LLC	2,588
43	WTG Fuels LLC	Auto Oil & Gas	Western Gas Interstate Co LLC	20,578
44	WTG Fuels LLC	Auto Oil & Gas	WTG Gas Transmission Company	8,762
45	WTG Fuels LLC	Auto Oil & Gas	WTG Hugoton L.P.	43,124
46	WTG Fuels LLC	Auto Oil & Gas	WTG NGL Pipeline Company LLC	8,508
47	WTG Fuels LLC	Auto Oil & Gas	WTG North Permian Midstream	444,427
48	WTG Fuels LLC	Auto Oil & Gas	WTG South Permian - Irion County	35,278
49	WTG Fuels LLC	Auto Oil & Gas	East Vealmoor Plant	277,580
50	WTG Fuels LLC	Auto Oil & Gas	WTG Gas Transmission Company LLC	2,738
51	WTG Fuels LLC	Auto Oil & Gas	WTG Jameson L.P.	119,885
52	WTG Fuels LLC	Auto Oil & Gas	Ledco LLC	3,860
53	WTG Fuels LLC	Auto Oil & Gas	WTG Midstream Marketing LLC	710
54	WTG Fuels LLC	Auto Oil & Gas	WTG South Permian Midstream LLC	638,599
61	WTG Fuels LLC	Oils, Lubricants, Other Products	East Vealmoor Plant	18,914
62	WTG Fuels LLC	Oils, Lubricants, Other Products	WTG Jameson L.P.	231,853
63	WTG Fuels LLC	Oils, Lubricants, Other Products	WTG North Permian Midstream	196,375
64	WTG Fuels LLC	Oils, Lubricants, Other Products	WTG South Permian - Irion County	8,880
65	WTG Fuels LLC	Oils, Lubricants, Other Products	WTG South Permian Midstream LLC	404,210
66	Western Gas Interstate Co LLC	Gas Transportation	WTG Gas Marketing LLC	790,140
67	Low Country Power	Electricity	WTG North Permian Midstream	25,033,505
68	**Total**			**1,324,937,683**

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Test Period Ending December 31, 2023

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COST OF SERVICE STUDY -- COST CLASSIFICATION

Description:	Texas Total	Joint	Jurisdictional Only	Non-Jurisdictional Only	Classification Factor	Joint		Jurisdictional Only		Non-Jurisidctional Only	
						Customer	Capacity	Customer	Capacity	Customer	Capacity
Plant in Service											
301 Organization	57,872	57,872	-	-	Other Gas Plant	34,891	22,981	-	-	-	-
302 Franchises and Consents	200,000	200,000	-	-	Other Gas Plant	120,580	79,420	-	-	-	-
303 Intangible Plant	341,866	279,535	62,331	-	Other Gas Plant	168,532	111,004	37,317	25,014	-	-
332 Field Lines	3,047,811	3,045,801	-	2,010	Aggregate	1,822,996	1,222,804	-	-	1,203	807
334 Field M&R Station Equipment	100,000	100,000	-	-	Aggregate	59,853	40,147	-	-	-	-
365 Land and Rights-of-Way	5,379,123	5,379,123	-	-	Aggregate	3,219,555	2,159,569	-	-	-	-
366 Structures and Improvements	-	-	-	-	Aggregate	-	-	-	-	-	-
367 Mains	45,312,827	36,636,145	7,808,497	868,185	Pipe	21,862,767	14,773,378	4,659,752	3,148,745	518,093	350,092
368 Compressor Station Equipment	38,984	38,984	-	-	Aggregate	23,333	15,651	-	-	-	-
369 M&R Station Equipment	1,413,460	1,310,842	97,790	4,828	Meters	930,995	379,847	69,453	28,337	3,429	1,399
371 Other Equipment	224,148	211,222	9,926	3,001	Aggregate	126,422	84,800	5,941	3,985	1,796	1,205
376 Mains	167,899,665	86,066,057	75,673,412	6,160,195	Pipe	51,360,267	34,705,791	45,158,413	30,514,998	3,676,121	2,484,074
377 Compressors	358,216	358,216	-	-	Aggregate	214,402	143,814	-	-	-	-
378 M&R Station Equipment - General	7,692,969	6,086,442	1,350,381	256,145	Meters	4,322,754	1,763,688	959,077	391,304	181,921	74,224
387 Other Equipment	687,636	646,525	31,536	9,574	Other Gas Plant	389,789	256,736	18,880	12,656	5,752	3,822
389 Rights-of-Way	6,499,511	6,494,591	4,920	-	Other Gas Plant	3,915,583	2,579,008	2,946	1,974	-	-
390 Office Buildings	4,562,846	4,272,167	114,869	175,809	Other Gas Plant	2,575,685	1,696,481	68,771	46,098	105,629	70,181
391 Office Furniture and Equipment	272,377	233,840	31,375	7,163	Other Gas Plant	140,982	92,858	18,784	12,591	4,303	2,859
392 Transportation Equip	2,900,187	2,797,249	25,393	77,545	Other Gas Plant	1,686,459	1,110,790	15,203	10,191	46,590	30,955
394 Tools, Shop & Garage	1,162,584	1,097,954	21,572	43,059	Other Gas Plant	661,955	435,998	12,915	8,657	25,870	17,188
396 Power Operated Equipment	356,492	356,492	-	-	Other Gas Plant	214,929	141,563	-	-	-	-
397 Communication Equip	523,132	140,756	324,654	57,722	Other Gas Plant	84,861	55,894	194,367	130,287	34,680	23,042
398 Miscellaneous Equip	134,907	88,608	41,186	5,113	Other Gas Plant	53,422	35,186	24,657	16,528	3,072	2,041
Total Plant in Service	**249,166,612**	**155,898,421**	**85,597,842**	**7,670,349**		**93,991,012**	**61,907,409**	**51,246,475**	**34,351,367**	**4,608,461**	**3,061,888**
Accumulated Depreciation											
301 Organization	(57,872)	(57,872)	-	-	Other Gas Plant	(34,891)	(22,981)	-	-	-	-
302 Franchises and Consents	(200,000)	(200,000)	-	-	Other Gas Plant	(120,580)	(79,420)	-	-	-	-
303 Intangible Plant	(626,340)	(626,340)	-	-	Other Gas Plant	(377,620)	(248,720)	-	-	-	-
332 Field Lines	(3,395,407)	(3,394,990)	-	(417)	Aggregate	(2,031,996)	(1,362,994)	-	-	(250)	(167)
334 Field M&R Station Equipment	(50,485)	(50,485)	-	-	Aggregate	(30,217)	(20,268)	-	-	-	-
365 Land and Rights-of-Way	(612,078)	(612,078)	-	-	Aggregate	(366,346)	(245,732)	-	-	-	-
366 Structures and Improvements	-	-	-	-	Aggregate	-	-	-	-	-	-
367 Mains	(13,446,426)	(12,686,741)	(661,067)	(98,618)	Pipe	(7,570,864)	(5,115,877)	(394,494)	(266,573)	(58,851)	(39,767)
368 Compressor Station Equipment	(49,512)	(49,512)	-	-	Aggregate	(29,634)	(19,878)	-	-	-	-
369 M&R Station Equipment	(799,842)	(790,602)	(8,108)	(1,132)	Meters	(561,507)	(229,095)	(5,758)	(2,349)	(804)	(328)
371 Other Equipment	(210,395)	(204,380)	(4,811)	(1,204)	Aggregate	(122,327)	(82,053)	(2,880)	(1,932)	(721)	(483)
376 Mains	(41,183,364)	(34,326,151)	(6,542,474)	(314,739)	Pipe	(20,484,269)	(13,841,882)	(3,904,248)	(2,638,226)	(187,822)	(126,917)
377 Compressors	(390,060)	(390,060)	-	-	Aggregate	(233,462)	(156,598)	-	-	-	-
378 M&R Station Equipment - General	(4,936,538)	(4,815,728)	(75,534)	(45,277)	Meters	(3,420,259)	(1,395,469)	(53,646)	(21,888)	(32,157)	(13,120)
387 Other Equipment	(548,063)	(535,357)	(10,493)	(2,213)	Other Gas Plant	(322,766)	(212,591)	(6,282)	(4,211)	(1,330)	(884)
389 Rights-of-Way	(2,566,501)	(2,566,501)	-	-	Other Gas Plant	(1,547,341)	(1,019,160)	-	-	-	-
390 Office Buildings	(1,378,613)	(1,325,557)	(17,846)	(35,210)	Other Gas Plant	(799,177)	(526,380)	(10,684)	(7,162)	(21,155)	(14,055)
391 Office Furniture and Equipment	(72,690)	(61,277)	(9,269)	(2,145)	Other Gas Plant	(36,944)	(24,333)	(5,549)	(3,720)	(1,288)	(856)
392 Transportation Equip	(1,194,963)	(1,145,917)	(25,792)	(23,254)	Other Gas Plant	(690,872)	(455,045)	(15,441)	(10,351)	(13,971)	(9,283)
394 Tools, Shop & Garage	(705,227)	(691,649)	(2,611)	(10,967)	Other Gas Plant	(416,994)	(274,654)	(1,563)	(1,048)	(6,589)	(4,378)
396 Power Operated Equipment	(296,313)	(296,313)	-	-	Other Gas Plant	(178,647)	(117,666)	-	-	-	-
397 Communication Equip	(232,331)	(33,379)	(166,705)	(32,247)	Other Gas Plant	(20,124)	(13,255)	(99,804)	(66,900)	(19,374)	(12,872)
398 Miscellaneous Equip	(37,027)	(21,270)	(14,043)	(1,714)	Other Gas Plant	(12,824)	(8,446)	(8,407)	(5,636)	(1,030)	(684)
Total Accumulated Depreciation	**(72,990,047)**	**(64,882,159)**	**(7,538,752)**	**(569,136)**		**(39,409,660)**	**(25,472,499)**	**(4,508,758)**	**(3,029,994)**	**(345,341)**	**(223,795)**

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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COST OF SERVICE STUDY -- COST CLASSIFICATION

Description:		Texas Total	Joint	Jurisdictional Only	Non-Jurisdictional Only	Classification Factor	Joint Customer	Joint Capacity	Jurisdictional Only Customer	Jurisdictional Only Capacity	Non-Jurisidctional Only Customer	Non-Jurisidctional Only Capacity
Other Rate Base Items												
	Prepayments	1,181,498	1,181,498	-	-	Total Gas Plant	445,686	293,552	243,000	162,887	21,852	14,519
	Materials and Supplies Inventories	1,851,614	1,851,614	-	-	Total Gas Plant	698,469	460,048	380,824	255,273	34,247	22,754
	Customer Deposits	(1,200,560)	(1,200,560)	-	-	Direct	(1,200,560)	-	-	-	-	-
	Contributions in Aid of Construction	(23,143,350)	(23,143,350)	-	-	CIAC	(7,342,251)	(4,961,235)	(5,977,807)	(4,039,397)	(490,926)	(331,734)
	Accumulated Deferred Income Taxes	(25,703,718)	(25,703,718)	-	-	Total Gas Plant	(9,695,996)	(6,386,291)	(5,286,523)	(3,543,644)	(475,403)	(315,861)
	Excess ADIT	(9,311,525)	(9,311,525)	-	-	Total Gas Plant	(3,512,508)	(2,313,522)	(1,915,116)	(1,283,734)	(172,221)	(114,425)
	Total Other Rate Basee Items	**(56,326,042)**	**(56,326,042)**	**-**	**-**		**(20,607,160)**	**(12,907,447)**	**(12,555,621)**	**(8,448,615)**	**(1,082,451)**	**(724,747)**
Rate Base		**119,850,523**					**33,974,192**	**23,527,463**	**34,182,097**	**22,872,757**	**3,180,669**	**2,113,346**
Operation and Maintenance Expenses												
813	Other Gas Supply Expenses	157,163	157,163	-	-	Total Gas Plant	59,285	39,048	32,324	21,667	2,907	1,931
858	Trans. & Comp. Of Gas by Others	-	-	-	-	Total Gas Plant	-	-	-	-	-	-
863	Maintenance of Mains	96,421	96,421	-	-	Pipe Plant	33,114	22,376	22,529	15,224	1,897	1,282
870	Operation Supervision & Engineering	6,967,030	6,967,030	-	-	Total Gas Plant	2,628,114	1,731,014	1,432,920	960,510	128,859	85,614
874	Mains and Services Expenses	1,119,415	1,119,415	-	-	Pipe Plant	384,438	259,777	261,557	176,742	22,021	14,880
880	Other Expenses	789,857	789,857	-	-	Total Gas Plant	297,951	196,246	162,451	108,894	14,609	9,706
881	Rents	200,696	200,696	-	-	Total Gas Plant	75,707	49,864	41,277	27,669	3,712	2,466
886	Maintenance of Structures	7,528	7,528	-	-	Total Gas Plant	2,840	1,870	1,548	1,038	139	93
887	Maintenance of Mains	395,212	395,212	-	-	Pipe Plant	135,727	91,715	92,343	62,399	7,774	5,253
888	Maint of M&R Station Equip-General	2,249	2,249	-	-	Meter Plant	1,298	529	254	104	46	19
889	Maint of M&R Station Equip-City Gate	440,411	440,411	-	-	Meter Plant	254,085	103,667	49,742	20,295	8,964	3,657
894	Maintenance of Other Equipment	520,385	520,385	-	-	Total Gas Plant	196,300	129,294	107,028	71,743	9,625	6,395
	Total O&M Expenses	**10,696,368**	**10,696,368**	**-**	**-**		**4,068,858**	**2,625,401**	**2,203,975**	**1,466,285**	**200,552**	**131,297**
Adminstrative and General Expenses												
904	Uncollectible Accounts	162,750	162,750	-	-	Total Gas Plant	61,393	40,437	33,473	22,438	3,010	2,000
910	Miscellaneous Customer Service Exp	123,824	123,824	-	-	Total Gas Plant	46,709	30,765	25,467	17,071	2,290	1,522
913	Advertising Expenses	21,153	21,153	-	-	O&M	8,047	5,192	4,359	2,900	397	260
920	Administrative and General Salaries	1,241,542	1,241,542	-	-	O&M	472,278	304,734	255,818	170,194	23,278	15,240
921	Office Supplies and Expenses	173,311	173,311	-	-	O&M	65,927	42,539	35,711	23,758	3,250	2,127
922	Administrative Expenses Transferred-Credit	(1,117,423)	(1,117,423)	-	-	O&M	(425,064)	(274,269)	(230,244)	(153,179)	(20,951)	(13,716)
923	Outside Services Employed	1,500,128	1,500,128	-	-	O&M	570,643	368,203	309,100	205,641	28,127	18,414
924	Property Insurance	867,137	867,137	-	-	Total Gas Plant	327,103	215,447	178,345	119,548	16,038	10,656
926	Employee Pension and Benefits	1,418,128	1,418,128	-	-	O&M	539,451	348,077	292,204	194,401	26,589	17,407
930	Miscellaneous General Expense	1,180,349	1,180,349	-	-	O&M	449,000	289,714	243,210	161,805	22,131	14,489
931	Rents	5,641	5,641	-	-	O&M	2,146	1,385	1,162	773	106	69
	Total A&G Expenses	**5,576,542**	**5,576,542**	**-**	**-**		**2,117,633**	**1,372,223**	**1,148,605**	**765,349**	**104,264**	**68,467**
Taxes Other than Income												
408	Payroll Taxes	602,078	602,078	-	-	A&G	228,633	148,154	124,010	82,632	11,257	7,392
408	Property Taxes	2,027,037	2,027,037	-	-	Total Gas Plant	764,642	503,633	416,904	279,458	37,491	24,909
408	Texas Franchise Tax	52,031	52,031	-	-	Total Gas Plant	19,627	12,927	10,701	7,173	962	639
408	Miscellaneous	111,076	111,076	-	-	Total Gas Plant	41,900	27,598	22,845	15,313	2,054	1,365
	Total Taxes Other than Income	**2,792,222**	**2,792,222**				**1,054,802**	**692,312**	**574,461**	**384,576**	**51,765**	**34,306**

WEST TEXAS GAS UTILITY, LLC
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Schedule J-1
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COST OF SERVICE STUDY -- COST CLASSIFICATION

Description:	Texas Total	Joint	Jurisdictional Only	Non-Jurisdictional Only	Classification Factor	Joint Customer	Joint Capacity	Jurisdictional Only Customer	Jurisdictional Only Capacity	Non-Jurisidctional Only Customer	Non-Jurisidctional Only Capacity
Depreciation and Amortization Expenses											
403 Plant Depreciation Expense	5,909,981	5,909,981	-	-	Total Gas Plant	2,229,372	1,468,381	1,215,515	814,780	109,308	72,625
CIAC Field Lines	(6,050)	(6,050)	-	-	CIAC-332	(3,619)	(2,427)	-	-	(2)	(2)
CIAC Mains	(42,363)	(42,363)	-	-	CIAC-367	(20,440)	(13,812)	(4,356)	(2,944)	(484)	(327)
CIAC Mains	(650,525)	(650,525)	-	-	CIAC-376	(198,995)	(134,467)	(174,966)	(118,230)	(14,243)	(9,625)
Total D&A Expenses	**5,211,043**					**2,006,319**	**1,317,675**	**1,036,193**	**693,606**	**94,578**	**62,671**
Return On Investment	**9,713,453**	9,713,453	-	-	Rate Base	**2,753,486**	**1,906,816**	**2,770,336**	**1,853,755**	**257,782**	**171,279**
Income Taxes	**1,713,989**	1,713,989	-	-	Rate Base	**485,867**	**336,468**	**488,840**	**327,105**	**45,487**	**30,223**
Other Income	**(1,087,324)**	(1,087,324)	-	-	Rev. Req.	**(380,280)**	**(251,274)**	**(250,407)**	**(167,214)**	**(22,975)**	**(15,174)**
REVENUE REQUIREMENTS	**34,616,294**					**12,106,686**	**7,999,622**	**7,972,003**	**5,323,462**	**731,453**	**483,070**

	Classification Factor Name	Joint		Juridictional			
		Total Texas		Domestic		Non-Domestic	
COST CLASSIFICATION FACTORS:		Customer	Capacity	Customer	Capacity	Customer	Capacity
Pipe (Schedule J-1)							
2-inch Pipe Replacement Cost		435,584,442					
Total System Pipe Replacement Cost		729,922,918					
Pipe Classification Factor	Pipe	**59.68%**	**40.32%**	**59.68%**	**40.32%**	**59.68%**	**40.32%**
Meters (Schedule J-2)							
Basic Meter Replacemet Cost		8,232,263					
Total System Meter Replacement Cost		11,591,033					
Meters Classification Factor	Meters	**71.02%**	**28.98%**	**71.02%**	**28.98%**	**71.02%**	**28.98%**
Aggregate (Schedules J-1 and J-2)							
2-inch Pipe and Basic Meter Replacement Cost		443,816,705					
Total System Pipe and Meter Replacement Cost		741,513,952					
Aggregate Classification Factor	Aggregate	**59.85%**	**40.15%**	**59.85%**	**40.15%**	**59.85%**	**40.15%**
Other Gas Plant		83,943,344	55,289,488	50,852,636	34,087,370	4,382,564	2,911,801
Other Gas Plant Classification Factor	Other Gas Plant	**60.29%**	**39.71%**	**59.87%**	**40.13%**	**60.08%**	**39.92%**
Total Gas Plant		93,991,012	61,907,409	51,246,475	34,351,367	4,608,461	3,061,888
Total Gas Plant	Total Gas Plant	**37.72%**	**24.85%**	**20.57%**	**13.79%**	**1.85%**	**1.23%**
Pipe Plant		73,223,033	49,479,169	49,818,166	33,663,744	4,194,214	2,834,166
Total Pipe Plant	Pipe Plant	**34.34%**	**23.21%**	**23.37%**	**15.79%**	**1.97%**	**1.33%**
Meter Plant		5,253,750	2,143,535	1,028,530	419,641	185,351	75,623
Total Meter Plant	Meter Plant	**57.69%**	**23.54%**	**11.29%**	**4.61%**	**2.04%**	**0.83%**

WEST TEXAS GAS UTILITY, LLC
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COST OF SERVICE STUDY -- COST CLASSIFICATION

Description:	Texas Total	Joint	Jurisdictional Only	Non-Jurisdictional Only	Classification Factor	Joint Customer	Joint Capacity	Jurisdictional Only Customer	Jurisdictional Only Capacity	Non-Jurisidctional Only Customer	Non-Jurisidctional Only Capacity
Contributions in Aid of Construction											
332 Field Lines	(54,418)	(54,418)	-	-	Plant 332	(32,549)	(21,833)	-	-	(21)	(14)
367 Mains	(1,397,789)	(1,397,789)	-	-	Plant 367	(674,412)	(455,722)	(143,742)	(97,131)	(15,982)	(10,799)
376 Mains	(21,691,143)	(21,691,143)	-	-	Plant 376	(6,635,290)	(4,483,679)	(5,834,065)	(3,942,266)	(474,922)	(320,920)
CIAC Allocation	**(23,143,350)**	**(23,143,350)**			CIAC	**(7,342,251)**	**(4,961,235)**	**(5,977,807)**	**(4,039,397)**	**(490,926)**	**(331,734)**
Operation and Maintenance Expenses						4,068,858	2,625,401	2,203,975	1,466,285	200,552	131,297
O&M Classification Factor					O&M	**38.04%**	**24.54%**	**20.60%**	**13.71%**	**1.87%**	**1.23%**
Administrative and General Expenses						2,117,633	1,372,223	1,148,605	765,349	104,264	68,467
A&G Classification Factor					A&G	**37.97%**	**24.61%**	**20.60%**	**13.72%**	**1.87%**	**1.23%**
Rate Base						33,974,192	23,527,463	34,182,097	22,872,757	3,180,669	2,113,346
Rate Base Classification Factor					Rate Base	**28.35%**	**19.63%**	**28.52%**	**19.08%**	**2.65%**	**1.76%**
Revenue Requirements						12,486,966	8,250,896	8,222,409	5,490,675	754,428	498,243
Revenue Requirements Classification Factor					Rev. Req.	**34.97%**	**23.11%**	**23.03%**	**15.38%**	**2.11%**	**1.40%**

WEST TEXAS GAS UTILITY, LLC
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COST OF SERVICE STUDY --- COST ALLOCATION

		Schedule J-1						Jurisdiction/Class Allocation						
								Cost	Juridictional					
		Joint Costs		Jurisdictional Only		Non-Jurisidctional Only		Allocation	Domestic		Non-Domestic		Non-Jurisidctional	
		Customer	Capacity	Customer	Capacity	Customer	Capacity	Factor	Customer	Capacity	Customer	Capacity	Customer	Capacity
Plant in Service														
301	Organization	34,891	22,981	-	-	-	-	Other Gas Plant	22,484	6,865	4,094	5,024	8,313	11,092
302	Franchises and Consents	120,580	79,420	-	-	-	-	Other Gas Plant	77,702	23,725	14,148	17,363	28,729	38,333
303	Intangible Plant	168,532	111,004	37,317	25,014	-	-	Other Gas Plant	140,172	47,603	25,523	34,838	40,154	53,577
332	Field Lines	1,822,996	1,222,804	-	-	1,203	807	Throughput	47,589	31,921	28,393	19,045	1,748,217	1,172,645
334	Field M&R Station Equipment	59,853	40,147	-	-	-	-	Throughput	1,562	1,048	932	625	57,358	38,474
365	Land and Rights-of-Way	3,219,555	2,159,569	-	-	-	-	Design Day	468,097	313,984	342,648	229,837	2,408,810	1,615,748
366	Structures and Improvements	-	-	-	-	-	-	Design Day	-	-	-	-	-	-
367	Mains	21,862,767	14,773,378	4,659,752	3,148,745	518,093	350,092	Design Day	5,869,051	3,965,908	4,296,161	2,903,055	16,875,400	11,403,253
368	Compressor Station Equipment	23,333	15,651	-	-	-	-	Design Day	3,392	2,276	2,483	1,666	17,457	11,710
369	M&R Station Equipment	930,995	379,847	69,453	28,337	3,429	1,399	Design Day	175,459	71,587	128,436	52,402	699,982	285,593
371	Other Equipment	126,422	84,800	5,941	3,985	1,796	1,205	Design Day	21,811	14,630	15,965	10,709	96,382	64,650
376	Mains	51,360,267	34,705,791	45,158,413	30,514,998	3,676,121	2,484,074	Customers/DD	78,800,655	22,664,271	10,919,704	16,590,305	10,474,443	28,450,288
377	Compressors	214,402	143,814	-	-	-	-	Customers/DD	163,382	20,909	22,641	15,306	28,379	107,599
378	M&R Station Equipment - General	4,322,754	1,763,688	959,077	391,304	181,921	74,224	Customers/DD	4,136,445	482,352	573,203	353,083	754,104	1,393,782
387	Other Equipment	389,789	256,736	18,880	12,656	5,752	3,822	Other Gas Plant	267,155	84,001	48,644	61,475	98,623	127,737
389	Rights-of-Way	3,915,583	2,579,008	2,946	1,974	-	-	Other Gas Plant	2,525,715	771,553	459,890	564,654	932,923	1,244,776
390	Office Buildings	2,575,685	1,696,481	68,771	46,098	105,629	70,181	Other Gas Plant	1,717,964	533,399	312,812	390,363	719,309	888,999
391	Office Furniture and Equipment	140,982	92,858	18,784	12,591	4,303	2,859	Other Gas Plant	106,740	35,009	19,436	25,621	37,894	47,678
392	Transportation Equip	1,686,459	1,110,790	15,203	10,191	46,590	30,955	Other Gas Plant	1,099,625	337,705	200,223	247,146	448,404	567,085
394	Tools, Shop & Garage	661,955	435,998	12,915	8,657	25,870	17,188	Other Gas Plant	437,493	135,242	79,660	98,976	183,587	227,626
396	Power Operated Equipment	214,929	141,563	-	-	-	-	Other Gas Plant	138,501	42,288	25,219	30,948	51,209	68,326
397	Communication Equip	84,861	55,894	194,367	130,287	34,680	23,042	Other Gas Plant	219,113	91,927	39,897	67,276	54,899	50,020
398	Miscellaneous Equip	53,422	35,186	24,657	16,528	3,072	2,041	Other Gas Plant	55,285	20,055	10,066	14,677	15,800	19,024
	Total Plant in Service	**93,991,012**	**61,907,409**	**51,246,475**	**34,351,367**	**4,608,461**	**3,061,888**		**96,495,392**	**29,698,257**	**17,570,179**	**21,734,394**	**35,780,378**	**47,888,012**
Accumulated Depreciation														
301	Organization	(34,891)	(22,981)	-	-	-	-	Gas Plant A/D	(20,686)	(4,307)	(3,670)	(3,148)	(10,535)	(15,526)
302	Franchises and Consents	(120,580)	(79,420)	-	-	-	-	Gas Plant A/D	(71,490)	(14,884)	(12,683)	(10,880)	(36,407)	(53,656)
303	Intangible Plant	(377,620)	(248,720)	-	-	-	-	Gas Plant A/D	(223,885)	(46,612)	(39,718)	(34,073)	(114,017)	(168,036)
332	Field Lines	(2,031,996)	(1,362,994)	-	-	(250)	(167)	Throughput	(53,045)	(35,581)	(31,649)	(21,229)	(1,947,551)	(1,306,352)
334	Field M&R Station Equipment	(30,217)	(20,268)	-	-	-	-	Throughput	(789)	(529)	(471)	(316)	(28,957)	(19,424)
365	Land and Rights-of-Way	(366,346)	(245,732)	-	-	-	-	Design Day	(53,264)	(35,727)	(38,989)	(26,153)	(274,093)	(183,852)
366	Structures and Improvements	-	-	-	-	-	-	Design Day	-	-	-	-	-	-
367	Mains	(7,570,864)	(5,115,877)	(394,494)	(266,573)	(58,851)	(39,767)	Design Day	(1,328,509)	(897,717)	(972,472)	(657,131)	(5,723,227)	(3,867,370)
368	Compressor Station Equipment	(29,634)	(19,878)	-	-	-	-	Design Day	(4,309)	(2,890)	(3,154)	(2,116)	(22,172)	(14,872)
369	M&R Station Equipment	(561,507)	(229,095)	(5,758)	(2,349)	(804)	(328)	Design Day	(84,963)	(34,665)	(62,193)	(25,375)	(420,913)	(171,733)
371	Other Equipment	(122,327)	(82,053)	(2,880)	(1,932)	(721)	(483)	Design Day	(19,448)	(13,045)	(14,236)	(9,549)	(92,243)	(61,874)
376	Mains	(20,484,269)	(13,841,882)	(3,904,248)	(2,638,226)	(187,822)	(126,917)	Customers/DD	(19,038,826)	(3,535,719)	(2,638,282)	(2,588,156)	(2,899,230)	(10,483,150)
377	Compressors	(233,462)	(156,598)	-	-	-	-	Customers/DD	(177,907)	(22,768)	(24,653)	(16,666)	(30,902)	(117,164)
378	M&R Station Equipment - General	(3,420,259)	(1,395,469)	(53,646)	(21,888)	(32,157)	(13,120)	Customers/DD	(2,653,479)	(215,527)	(367,703)	(157,766)	(484,881)	(1,057,183)
387	Other Equipment	(322,766)	(212,591)	(6,282)	(4,211)	(1,330)	(884)	Gas Plant A/D	(196,699)	(42,274)	(34,895)	(30,901)	(98,784)	(144,510)
389	Rights-of-Way	(1,547,341)	(1,019,160)	-	-	-	-	Gas Plant A/D	(917,396)	(190,998)	(162,749)	(139,616)	(467,196)	(688,546)
390	Office Buildings	(799,177)	(526,380)	(10,684)	(7,162)	(21,155)	(14,055)	Gas Plant A/D	(482,895)	(102,785)	(85,667)	(75,134)	(262,454)	(369,679)
391	Office Furniture and Equipment	(36,944)	(24,333)	(5,549)	(3,720)	(1,288)	(856)	Gas Plant A/D	(26,616)	(6,709)	(4,722)	(4,904)	(12,443)	(17,295)
392	Transportation Equip	(690,872)	(455,045)	(15,441)	(10,351)	(13,971)	(9,283)	Gas Plant A/D	(422,723)	(91,258)	(74,992)	(66,708)	(222,570)	(316,712)
394	Tools, Shop & Garage	(416,994)	(274,654)	(1,563)	(1,048)	(6,589)	(4,378)	Gas Plant A/D	(248,558)	(52,077)	(44,095)	(38,068)	(132,494)	(189,935)
396	Power Operated Equipment	(178,647)	(117,666)	-	-	-	-	Gas Plant A/D	(105,917)	(22,051)	(18,790)	(16,119)	(53,940)	(79,495)
397	Communication Equip	(20,124)	(13,255)	(99,804)	(66,900)	(19,374)	(12,872)	Gas Plant A/D	(96,698)	(41,133)	(17,154)	(30,067)	(25,451)	(21,827)
398	Miscellaneous Equip	(12,824)	(8,446)	(8,407)	(5,636)	(1,030)	(684)	Gas Plant A/D	(14,744)	(4,839)	(2,616)	(3,537)	(4,902)	(6,390)
	Total Accumulated Depreciation	**(39,409,660)**	**(25,472,499)**	**(4,508,758)**	**(3,029,994)**	**(345,341)**	**(223,795)**		**(26,242,845)**	**(5,414,095)**	**(4,655,551)**	**(3,957,611)**	**(13,365,362)**	**(19,354,582)**

WEST TEXAS GAS UTILITY, LLC
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COST OF SERVICE STUDY --- COST ALLOCATION

		Schedule J-1						Cost	Jurisdiction/Class Allocation					
									Juridictional					
		Joint Costs		Jurisdictional Only		Non-Jurisidctional Only		Allocation	Domestic		Non-Domestic		Non-Jurisidctional	
		Customer	Capacity	Customer	Capacity	Customer	Capacity	Factor	Customer	Capacity	Customer	Capacity	Customer	Capacity
Other Rate Base Items														
	Prepayments	445,686	293,552	243,000	162,887	21,852	14,519	Total Gas Plant	492,576	181,831	89,690	133,071	128,274	156,057
	Materials and Supplies Inventories	698,469	460,048	380,824	255,273	34,247	22,754	Total Gas Plant	771,952	284,961	140,559	208,546	201,028	244,568
	Customer Deposits	(1,200,560)	-	-	-	-	-	Customers	(914,871)	-	(126,777)	-	(158,913)	-
	Contributions in Aid of Construction	(7,342,251)	(4,961,235)	(5,977,807)	(4,039,397)	(490,926)	(331,734)	CIAC	(9,885,784)	(3,849,356)	(1,778,875)	(2,817,114)	(2,146,325)	(2,665,896)
	Accumulated Deferred Income Taxes	(9,695,996)	(6,386,291)	(5,286,523)	(3,543,644)	(475,403)	(315,861)	Total Gas Plant	(10,716,081)	(3,955,762)	(1,951,217)	(2,894,988)	(2,790,624)	(3,395,047)
	Excess ADIT	(3,512,508)	(2,313,522)	(1,915,116)	(1,283,734)	(172,221)	(114,425)	Total Gas Plant	(3,882,048)	(1,433,029)	(706,855)	(1,048,749)	(1,010,942)	(1,229,902)
	Total Other Rate Basee Items	**(20,607,160)**	**(12,907,447)**	**(12,555,621)**	**(8,448,615)**	**(1,082,451)**	**(724,747)**		**(24,134,255)**	**(8,771,356)**	**(4,333,475)**	**(6,419,234)**	**(5,777,502)**	**(6,890,220)**
Rate Base		**33,974,192**	**23,527,463**	**34,182,097**	**22,872,757**	**3,180,669**	**2,113,346**		**46,118,291**	**15,512,807**	**8,581,153**	**11,357,548**	**16,637,513**	**21,643,210**
Operation and Maintenance Expenses														
813	Other Gas Supply Expenses	59,285	39,048	32,324	21,667	2,907	1,931	Throughput	21,793	14,590	13,002	8,705	59,721	39,352
858	Trans. & Comp. Of Gas by Others	-	-	-	-	-	-	Throughput	-	-	-	-	-	-
863	Maintenance of Mains	33,114	22,376	22,529	15,224	1,897	1,282	Customers/DD	45,021	12,043	6,239	8,815	6,280	18,023
870	Operation Supervision & Engineering	2,628,114	1,731,014	1,432,920	960,510	128,859	85,614	Customers/DD	3,261,240	806,241	451,922	590,171	476,730	1,380,726
874	Mains and Services Expenses	384,438	259,777	261,557	176,742	22,021	14,880	Customers/DD	522,679	139,815	72,430	102,345	72,907	209,240
880	Other Expenses	297,951	196,246	162,451	108,894	14,609	9,706	Customers/DD	369,729	91,404	51,235	66,908	54,047	156,534
881	Rents	75,707	49,864	41,277	27,669	3,712	2,466	Customers/DD	93,945	23,225	13,018	17,001	13,733	39,774
886	Maintenance of Structures	2,840	1,870	1,548	1,038	139	93	Customers/DD	3,524	871	488	638	515	1,492
887	Maintenance of Mains	135,727	91,715	92,343	62,399	7,774	5,253	Customers/DD	184,533	49,362	25,571	36,133	25,740	73,873
888	Maint of M&R Station Equip-General	1,298	529	254	104	46	19	Customers/DD	1,212	137	168	100	218	415
889	Maint of M&R Station Equip-City Gate	254,085	103,667	49,742	20,295	8,964	3,657	Customers/DD	237,311	26,790	32,885	19,610	42,596	81,219
894	Maintenance of Other Equipment	196,300	129,294	107,028	71,743	9,625	6,395	Customers/DD	243,590	60,220	33,755	44,081	35,608	103,130
	Total O&M Expenses	**4,068,858**	**2,625,401**	**2,203,975**	**1,466,285**	**200,552**	**131,297**		**4,984,576**	**1,224,698**	**700,714**	**894,507**	**788,095**	**2,103,778**
Adminstrative and General Expenses														
904	Uncollectible Accounts	61,393	40,437	33,473	22,438	3,010	2,000	Customers/DD	76,183	18,834	10,557	13,786	11,136	32,254
910	Miscellaneous Customer Service Exp	46,709	30,765	25,467	17,071	2,290	1,522	Customers/DD	57,962	14,329	8,032	10,489	8,473	24,540
913	Advertising Expenses	8,047	5,192	4,359	2,900	397	260	Customers/DD	9,960	2,429	1,380	1,778	1,462	4,144
920	Administrative and General Salaries	472,278	304,734	255,818	170,194	23,278	15,240	O&M	587,948	186,731	82,652	136,386	80,775	167,050
921	Office Supplies and Expenses	65,927	42,539	35,711	23,758	3,250	2,127	O&M	82,074	26,066	11,538	19,039	11,276	23,319
922	Administrative Expenses Transferred-Credit	(425,064)	(274,269)	(230,244)	(153,179)	(20,951)	(13,716)	O&M	(529,170)	(168,063)	(74,389)	(122,752)	(72,700)	(150,350)
923	Outside Services Employed	570,643	368,203	309,100	205,641	28,127	18,414	O&M	710,405	225,623	99,866	164,793	97,599	201,843
924	Property Insurance	327,103	215,447	178,345	119,548	16,038	10,656	Customers/DD	405,903	100,347	56,248	73,454	59,335	171,849
926	Employee Pension and Benefits	539,451	348,077	292,204	194,401	26,589	17,407	O&M	671,572	213,290	94,407	155,785	92,264	190,810
930	Miscellaneous General Expense	449,000	289,714	243,210	161,805	22,131	14,489	O&M	558,969	177,527	78,578	129,664	76,794	158,817
931	Rents	2,146	1,385	1,162	773	106	69	O&M	2,671	848	376	620	367	759
	Total A&G Expenses	**2,117,633**	**1,372,223**	**1,148,605**	**765,349**	**104,264**	**68,467**		**2,634,477**	**797,962**	**369,244**	**583,043**	**366,781**	**825,035**
Taxes Other than Income														
408	Payroll Taxes	228,633	148,154	124,010	82,632	11,257	7,392	A&G	287,630	104,193	40,434	76,101	35,836	57,883
408	Property Taxes	764,642	503,633	416,904	279,458	37,491	24,909	Customers/DD	948,848	234,574	131,485	171,708	138,703	401,718
408	Texas Franchise Tax	19,627	12,927	10,701	7,173	962	639	Cost of Service	23,723	8,862	3,837	6,482	3,731	5,396
408	Miscellaneous	41,900	27,598	22,845	15,313	2,054	1,365	Throughput	15,402	10,312	9,189	6,152	42,208	27,812
	Total Taxes Other than Income	**1,054,802**	**692,312**	**574,461**	**384,576**	**51,765**	**34,306**		**1,275,604**	**357,940**	**184,946**	**260,444**	**220,478**	**492,810**

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

COST OF SERVICE STUDY --- COST ALLOCATION

	Schedule J-1						Cost Allocation Factor	Jurisdiction/Class Allocation: Juridictional: Domestic		Jurisdiction/Class Allocation: Juridictional: Non-Domestic		Jurisdiction/Class Allocation: Non-Jurisidctional	
	Customer	**Capacity**	**Customer**	**Capacity**	**Customer**	**Capacity**	**Factor**	**Customer**	**Capacity**	**Customer**	**Capacity**	**Customer**	**Capacity**
Depreciation and Amortization Expenses													
403 Plant Depreciation Expense	2,229,372	1,468,381	1,215,515	814,780	109,308	72,625	Total Gas Plant	2,463,917	909,537	448,638	665,636	641,640	780,613
CIAC Field Lines	(3,619)	(2,427)	-	-	(2)	(2)	CIAC	(2,375)	(742)	(427)	(543)	(818)	(1,144)
CIAC Mains	(20,440)	(13,812)	(4,356)	(2,944)	(484)	(327)	CIAC	(17,109)	(5,923)	(3,079)	(4,335)	(5,093)	(6,825)
CIAC Mains	(198,995)	(134,467)	(174,966)	(118,230)	(14,243)	(9,625)	CIAC	(278,907)	(109,382)	(50,187)	(80,050)	(59,109)	(72,889)
Total D&A Expenses	**2,006,319**	**1,317,675**	**1,036,193**	**693,606**	**94,578**	**62,671**		**2,165,526**	**793,490**	**394,944**	**580,708**	**576,620**	**699,756**
Return On Investment	**2,753,486**	**1,906,816**	**2,770,336**	**1,853,755**	**257,782**	**171,279**	Rate Base	4,115,818	1,679,938	765,823	1,229,950	899,962	1,021,961
Income Taxes	**485,867**	**336,468**	**488,840**	**327,105**	**45,487**	**30,223**	Rate Base	726,257	296,434	135,134	217,031	158,803	180,330
Other Income	**(380,280)**	**(251,274)**	**(250,407)**	**(167,214)**	**(22,975)**	**(15,174)**	Cost of Service	(496,708)	(188,303)	(80,342)	(137,725)	(76,612)	(107,633)
COST OF SERVICE	**12,106,686**	**7,999,622**	**7,972,003**	**5,323,462**	**731,453**	**483,070**		**15,405,551**	**4,962,159**	**2,470,463**	**3,627,958**	**2,934,127**	**5,216,036**
COST ALLOCATION FACTORS:													
Customer Count (Schedule K)								17,924		2,484		3,113	
Customer Allocation Factor -- Joint Costs							Customers	**76.20%**	**0.00%**	**10.56%**	**0.00%**	**13.24%**	**0.00%**
Customer Allocation Factor -- Jurisdicational Only Costs								**87.83%**	**0.00%**	**12.17%**	**0.00%**		
Customer Allocation Factor -- Non-Jurisdicational Only Costs												**100.00%**	**0.00%**
Design Day (Schedule J-5)									20,593		15,074		105,970
Design Day Allocation Factor -- Joint Costs							Design Day	**14.54%**	**14.54%**	**10.64%**	**10.64%**	**74.82%**	**74.82%**
Design Day Allocation Factor -- Jurisdicational Costs								**57.74%**	**57.74%**	**42.26%**	**42.26%**		
Design Day Allocation Factor -- Non-Jurisdicational Costs												**100.00%**	**100.00%**
Throughput (Schedule K)									1,063,235		634,364		39,031,669
Throughput Allocation Factor -- Joint Costs							Throughput	**2.61%**	**2.61%**	**1.56%**	**1.56%**	**95.83%**	**95.83%**
Throughput Allocation Factor -- Jurisdictional Costs								**62.63%**	**62.63%**	**37.37%**	**37.37%**		
Throughput Allocation Factor -- Non-Jurisdictional Costs												**100.00%**	**100.00%**
Other Gas Plant								89,687,444	27,568,885	16,330,567	20,176,032	33,160,534	44,543,741
Other Gas Plant Allocation Factor -- Joint Costs							Other Gas Plant	**64.44%**	**29.87%**	**11.73%**	**21.86%**	**23.83%**	**48.27%**
Other Gas Plant Allocation Factor -- Jurisdictional Costs								**84.60%**	**57.74%**	**15.40%**	**42.26%**		
Other Gas Plant Allocation Factor -- Non-Jurisdictional Costs												**100.00%**	**100.00%**
Other Gas Plant Accumulated Depreciation								(23,414,538)	(4,794,169)	(4,153,801)	(3,504,456)	(11,924,170)	(17,282,973)
Other Gas Plant Acc. Dep. Allocation Factor -- Joint Costs							Gas Plant A/D	**59.29%**	**18.74%**	**10.52%**	**13.70%**	**30.19%**	**67.56%**
Other Gas Plant Acc. Dep. Allocation Factor -- Jurisdictional Costs								**84.93%**	**57.77%**	**15.07%**	**42.23%**		
Other Gas Plant Acc. Dep. Allocation Factor -- Non-Jurisdictional Costs												**100.00%**	**100.00%**

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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COST OF SERVICE STUDY --- COST ALLOCATION

								Jurisdiction/Class Allocation					
							Cost	Juridictional					
							Allocation	Domestic		Non-Domestic		Non-Jurisidctional	
	Customer	Capacity	Customer	Capacity	Customer	Capacity	Factor	Customer	Capacity	Customer	Capacity	Customer	Capacity
Contributions in Aid of Construction													
332 Field Lines							Plant 332	47,589	31,921	28,393	19,045	1,748,217	1,172,645
367 Mains							Plant 367	5,869,051	3,965,908	4,296,161	2,903,055	16,875,400	11,403,253
376 Mains							Plant 376	78,800,655	22,664,271	10,919,704	16,590,305	10,474,443	28,450,288
Total CIAC								84,717,295	26,662,099	15,244,258	19,512,405	29,098,060	41,026,185
CIAC Allocation Factor -- Joint Costs								**65.64%**	**30.58%**	**11.81%**	**22.38%**	**22.55%**	**47.05%**
CIAC Allocation Factor -- Jurisdictional Costs								**84.75%**	**57.74%**	**15.25%**	**42.26%**		
CIAC Allocation Factor -- Non-Jurisdicational Costs												**100.00%**	**100.00%**
Operation and Maintenance Expenses								4,984,576	1,224,698	700,714	894,507	788,095	2,103,778
O&M Allocation Factor -- Joint Costs							O&M	**77.00%**	**29.00%**	**10.82%**	**21.18%**	**12.17%**	**49.82%**
O&M Allocation Factor -- Jurisdictional Costs								**87.67%**	**57.79%**	**12.33%**	**42.21%**		
O&M Allocation Factor -- Non-Jurisdictional Costs												**100.00%**	**100.00%**
Administrative and General Expenses (Account 920)								587,948	186,731	82,652	136,386	80,775	167,050
A&G Allocation Factor -- Joint Costs							A&G	**78.25%**	**38.10%**	**11.00%**	**27.82%**	**10.75%**	**34.08%**
A&G Allocation Factor -- Jurisdictional Costs								**87.67%**	**57.79%**	**12.33%**	**42.21%**		
A&G Allocation Factor -- Non-Jurisdictional Costs												**100.00%**	**100.00%**
Total Gas Plant								96,495,392	29,698,257	17,570,179	21,734,394	35,780,378	47,888,012
Total Gas Plant Allocation Factor -- Joint Costs							Gas Plant	**64.40%**	**29.90%**	**11.73%**	**21.88%**	**23.88%**	**48.22%**
Total Gas Plant Allocation Factor -- Jurisdictional Costs								**84.60%**	**57.74%**	**15.40%**	**42.26%**		
Total Gas Plant Allocation Factor -- Non-Jurisdictional Costs												**100.00%**	**100.00%**
Rate Base								46,118,291	15,512,807	8,581,153	11,357,548	16,637,513	21,643,210
Rate Base Allocation Factor -- Joint Costs							Rate Base	**64.65%**	**31.98%**	**12.03%**	**23.41%**	**23.32%**	**44.61%**
Rate Base Allocation Factor -- Jurisdictional Costs								**84.31%**	**57.73%**	**15.69%**	**42.27%**		
Rate Base Allocation Factor -- Non-Jurisdictional Costs												**100.00%**	**100.00%**
Cost of Service								14,626,655	4,792,522	2,365,859	3,505,239	2,790,261	4,830,859
Cost of ServiceAllocation Factor -- Joint Costs							Cost of Service	**73.94%**	**36.50%**	**11.96%**	**26.70%**	**14.10%**	**36.80%**
Cost of Service Allocation Factor -- Jurisdictional Costs								**86.08%**	**57.76%**	**13.92%**	**42.24%**		
Cost of ServiceAllocation Factor -- Non-Jurisdictional Costs												**100.00%**	**100.00%**

WEST TEXAS GAS UTILITY, LLC **Schedule J-3**
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PIPE REPLACEMENT COST ANALYSIS

Pipe Size (inches)	Installed Length (feet)	Replacement Cost (per foot)	Total System Replacement Cost	Replacement Cost with 2-inch Pipe
				14.50
0.50	2,606	12.00	31,271	37,786
0.75	6,545	12.00	78,541	94,904
1.00	350,234	12.00	4,202,807	5,078,392
1.25	238,216	14.50	3,454,128	3,454,128
1.50	173,872	14.50	2,521,150	2,521,150
2.00	14,715,074	14.50	213,368,566	213,368,566
2.25	63,559	14.50	921,609	921,609
2.50	46,961	14.50	680,940	680,940
2.75	31,779	14.50	460,796	460,796
2.88	64,165	14.50	930,400	930,400
3.00	3,864,549	21.00	81,155,528	56,035,960
3.38	109,566	21.00	2,300,878	1,588,701
3.50	15,211	21.00	319,437	220,564
4.00	5,147,519	28.00	144,130,544	74,639,032
5.00	13,737	28.00	384,622	199,179
6.00	3,571,122	40.00	142,844,875	51,781,267
8.00	444,825	54.00	24,020,546	6,449,961
10.00	782,462	63.00	49,295,135	11,345,706
12.00	202,613	73.00	14,790,734	2,937,886
22.00	195,691	225.00	44,030,410	2,837,515
Totals	**30,040,306**		**729,922,918**	**435,584,442**

Customer-related Cost Percentage	**59.68%**
Capacity-related Cost Percentage	**40.32%**

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

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METER REPLACEMENT COST ANALYSIS

Description	Number of Services	Cost per Service Meter	Cost per Service Riser	Cost per Service Total	Total Service Replacement Cost	Replacement Cost with Residential Meter
						350.00
Residential Meters	17,924	100.00	250.00	350.00	6,273,283	6,273,283
Small Commercial Meters	2,463	500.00	250.00	750.00	1,846,875	861,875
Irrigation Meters	2,942	750.00	250.00	1,000.00	2,942,417	1,029,846
Large Commercial Meters	192	2,500.00	250.00	2,750.00	528,458	67,258
Totals	**23,521**				**11,591,033**	**8,232,263**
Customer-related Cost Percentage						**71.02%**
Capacity-related Cost Percentage						**28.98%**

WEST TEXAS GAS UTILITY, LLC **Schedule J-5**
Test Period Ending December 31, 2023 **Page 1 of 1**

DESIGN DAY ANALYSIS

Description	Reference	Peak Design Day -- January 2023 North	West	South	Total
JURISDICTIONAL:					
Domestic					
Adjusted Mcf per day -- January 2023	Sch. K-1,K-2,K-3	3,977.88	1,648.23	626.26	6,252.38
Base Use -- Mcf per day	Sch. K-4,K-5,K-6	482.98	241.89	77.10	801.98
Adjusted Weather Sensitive Load -- Mcf per day		3,494.90	1,406.34	549.16	5,450.40
Heating Degree Days per day -- January 2023	Sch. K-4,K-5,K-6	24.13	17.74	8.13	
Heat Load Volume per HDD		144.84	79.27	67.56	
Design Day HDD's		73.00	66.00	59.00	
Design Day Heat Load Volume -- Mcf per day		10,573.47	5,231.58	3,985.79	19,790.84
Anticipated Design Day Volume -- Mcf per day		11,056.46	5,473.47	4,062.89	20,592.81
Non-Domestic					
Adjusted Mcf per day -- January 2023	Sch. K-1,K-2,K-3	1,983.49	1,983.49	693.77	4,660.74
Base Use -- Mcf per day	Sch. K-4,K-5,K-6	184.37	515.46	250.12	949.96
Adjusted Weather Sensitive Load -- Mcf per day		1,799.12	1,468.03	443.64	3,710.79
Heating Degree Days per day -- January 2023	Sch. K-4,K-5,K-6	24.13	17.74	8.13	
Heat Load Volume per HDD		74.56	82.74	54.58	
Design Day HDD's		73.00	66.00	59.00	
Design Day Heat Load Volume -- Mcf per day		5,443.05	5,461.06	3,219.93	14,124.04
Anticipated Design Day Volume -- Mcf per day		5,627.42	5,976.52	3,470.05	15,073.99
NON-JURISDICTIONAL:					
Non-Domestic					
Adjusted Mcf per day -- January 2023	Sch. K-1,K-2,K-3	1,983.49	1,330.57	2,076.20	5,390.26
Base Use -- Mcf per day	Sch. K-4,K-5,K-6	184.37	1,008.23	1,350.27	2,542.87
Adjusted Weather Sensitive Load -- Mcf per day		1,799.12	322.34	725.93	2,847.39
Heating Degree Days per day -- January 2023	Sch. K-4,K-5,K-6	24.13	17.74	8.13	
Heat Load Volume per HDD		74.56	-	89.30	
Design Day HDD's		73.00	66.00	59.00	
Design Day Heat Load Volume -- Mcf per day		5,443.05	-	5,268.77	10,711.82
Anticipated Design Day Volume -- Mcf per day		5,627.42	1,008.23	6,619.03	13,254.68
Interstate					
Mcf per day -- January 2023	Sch. K-1,K-2,K-3	1,026.40	-	-	1,026.40
Irrigation					
Mcf per day -- 2023 Test Year	Sch. K-1,K-2,K-3	45,226.93	1,318.99	128.84	46,674.77
Resale					
Mcf per day -- January 2023	Sch. K-1,K-2,K-3	4,815.26	-	-	4,815.26
Transportation					
Mcf per day -- January 2023	Sch. K-1,K-2,K-3	3,347.94	3,347.94	33,502.89	40,198.77
Gathering					
Mcf per day -- January 2023	Sch. K-1,K-2,K-3	-	-	-	-
Total Non-Jurisdictional		**60,043.95**	**5,675.16**	**40,250.76**	**105,969.88**
					141,636.69

WEST TEXAS GAS UTILITY, LLC **Schedule K**
Test Period Ending December 31, 2023 **Page 1 of 1**

SUMMARY OF ADJUSTED TEST YEAR BILLING UNITS

ALL ZONES

	Reference	Description	2023 Unadjusted	2023 Weather Adj.	2023 Adjusted
JURISDICTIONAL:					
Domestic:					
Mcf	Schedules K-1 to K-9	Weather Adjusted	1,007,056	56,179	1,063,235
# Customers	Schedules K-1 to K-9	Test Year	17,924	-	17,924
Non-Domestic:					
Public Authority					
Mcf	Schedules K-1 to K-9	Weather Adjusted	187,925	13,275	201,200
# Customers	Schedules K-1 to K-9	Test Year	738	-	738
Small Commercial					
Mcf	Schedules K-1 to K-9	Weather Adjusted	355,076	16,588	371,663
# Customers	Schedules K-1 to K-9	Test Year	1,725	-	1,725
Large Commercial					
Mcf	Schedules K-1 to K-9	Weather Adjusted	58,671	2,830	61,501
# Customers	Schedules K-1 to K-9	Test Year	21	-	21
Total Jurisdictional					
Mcf			**1,608,728**	**88,872**	**1,697,599**
# Customers			**20,407**	**-**	**20,407**
NON-JURISDICTIONAL:					
Public Authority					
Mcf	Schedules K-1 to K-9	Weather Adjusted	41,249	1,301	42,551
# Customers	Schedules K-1 to K-9	Test Year	12	0	12
Interstate					
Mcf	Schedules K-1 to K-9	Test Year	517,941	-	517,941
# Customers	Schedules K-1 to K-9	Test Year	14	-	14
Small Commercial					
Mcf	Schedules K-1 to K-9	Weather Adjusted	3,651,532	31,722	3,683,255
# Customers	Schedules K-1 to K-9	Test Year	112	-	112
Large Commercial					
Mcf	Schedules K-1 to K-9	Weather Adjusted	2,879,551	17,548	2,897,099
# Customers	Schedules K-1 to K-9	Test Year	10	(0)	10
Irrigation					
Mcf	Schedules K-1 to K-9	Test Year	17,036,291	-	17,036,291
# Customers	Schedules K-1 to K-9	Test Year	2,942	-	2,942
Resale					
Mcf	Schedules K-1 to K-9	Test Year	1,538,737	-	1,538,737
# Customers	Schedules K-1 to K-9	Test Year	2	-	2
Transportation					
Mcf	Schedules K-1 to K-9	Test Year	13,105,914	-	13,105,914
# Customers	Schedules K-1 to K-9	Test Year	18	0	18
Gathering					
Mcf	Schedules K-1 to K-9	Test Year	209,882	-	209,882
# Customers	Schedules K-1 to K-9	Test Year	3	-	3
Intercompany					
Mcf	Eliminated	Eliminated	603,357	(603,357)	-
# Customers	Eliminated	Eliminated	16	(16)	-
Total Non-Jurisdictional					
Mcf			**39,584,455**	**(552,785)**	**39,031,669**
# Customers			**3,130**	**(16)**	**3,113**
TOTAL ALL ZONEs					
Mcf			**41,193,182**	**(463,913)**	**40,729,269**
# Customers			**23,537**	**(16)**	**23,521**

WEST TEXAS GAS UTILITY, LLC **Schedule K-1**
Test Period Ending December 31, 2023 **Page 1 of 1**

ADJUSTED TEST YEAR BILLING UNITS

NORTH ZONE

	Reference	January 2023	February	March	April	May	June	July	August	September	October	November	December	Total
JURISDICTIONAL:														
Domestic:														
Mcf	Schedule K-4	123,314	130,030	80,152	39,768	30,338	16,786	11,866	17,293	13,684	25,032	74,059	104,074	666,395
# Customers	Schedule K-7	9,443	9,377	9,418	9,392	9,383	9,355	9,325	9,343	9,357	9,387	9,462	9,490	9,394
Non-Domestic:														
Public Authority														
Mcf	Schedule K-4	27,586	23,273	14,426	6,371	4,059	1,964	1,350	1,651	1,353	3,372	12,249	21,967	119,622
# Customers	Schedule K-7	382	368	368	369	370	368	368	369	368	370	371	372	370
Small Commercial														
Mcf	Schedule K-4	33,707	34,139	24,066	10,859	7,699	3,829	3,739	(3,619)	12,999	6,187	17,915	31,051	182,571
# Customers	Schedule K-7	962	970	979	972	968	957	953	956	959	964	973	987	967
Large Commercial														
Mcf	Schedule K-4	195	183	140	37	26	2	3	3	2	11	81	188	871
# Customers	Schedule K-7	4	4	5	4	4	4	4	4	4	4	4	4	4
Total Jurisdictional														
Mcf		**184,802**	**187,625**	**118,784**	**57,035**	**42,122**	**22,580**	**16,958**	**15,328**	**28,038**	**34,603**	**104,304**	**157,280**	**969,460**
# Customers		**10,791**	**10,719**	**10,770**	**10,737**	**10,725**	**10,684**	**10,650**	**10,672**	**10,688**	**10,725**	**10,810**	**10,853**	**10,735**
NON-JURISDICTIONAL:														
Public Authority														
Mcf	Schedule K-4	4,163	5,918	3,956	2,002	1,370	1,433	1,132	1,260	1,128	1,745	3,269	4,160	31,536
# Customers	Schedule K-7	(4)	6	7	7	7	6	6	7	7	7	7	7	6
Interstate														
Mcf	Schedule K-7	31,818	24,145	39,127	46,424	46,939	20,793	50,572	81,449	66,299	45,792	37,603	26,979	517,941
# Customers	Schedule K-7	15	15	14	15	15	13	13	12	13	14	14	14	14
Small Commercial														
Mcf	Schedule K-4	240,325	222,132	214,518	168,108	255,553	179,734	172,753	205,192	263,715	240,153	266,908	269,793	2,698,884
# Customers	Schedule K-7	74	81	78	75	76	71	69	70	69	77	78	77	75
Large Commercial														
Mcf	Schedule K-4	262,899	255,002	246,990	230,638	232,487	219,283	186,185	219,338	222,616	238,307	248,913	243,159	2,805,817
# Customers	Schedule K-7	6	6	5	6	6	5	5	6	6	7	7	7	6
Irrigation														
Mcf	Schedule K-7	544,204	513,832	1,574,604	2,218,811	1,431,838	632,749	2,123,117	3,202,238	2,104,611	1,201,189	627,337	333,301	16,507,830
# Customers	Schedule K-7	2,096	2,225	2,908	3,053	2,888	2,716	3,005	3,029	3,034	2,719	2,469	1,831	2,664
Resale														
Mcf	Schedule K-7	149,273	119,108	202,577	188,532	96,242	41,770	172,676	188,488	118,945	70,290	103,622	87,214	1,538,737
# Customers	Schedule K-7	3	2	2	2	2	2	2	2	3	3	4	2	2
Transportation														
Mcf	Schedule K-7	103,786	87,419	71,435	41,081	26,828	21,861	(28,113)	15,855	16,265	30,993	57,021	83,686	528,118
# Customers	Schedule K-7	12	12	12	12	12	12	11	9	9	11	11	11	11
Gathering														
Mcf	Schedule K-7	-	1,717	1,702	25,656	24,485	22,911	24,064	23,741	21,833	27,203	21,164	15,406	209,882
# Customers	Schedule K-7	-	2	2	3	3	3	3	3	3	3	3	3	3
Intercompany														
Mcf	Eliminated													
# Customers	Eliminated													
Total Non-Jurisdictional														
Mcf		**1,336,468**	**1,229,273**	**2,354,909**	**2,921,252**	**2,115,742**	**1,140,534**	**2,702,384**	**3,937,562**	**2,815,412**	**1,855,672**	**1,365,839**	**1,063,698**	**24,838,746**
# Customers		**2,202**	**2,349**	**3,028**	**3,173**	**3,009**	**2,828**	**3,114**	**3,138**	**3,144**	**2,841**	**2,593**	**1,952**	**2,781**
TOTAL NORTH ZONE														
Mcf		**1,521,270**	**1,416,898**	**2,473,692**	**2,978,288**	**2,157,864**	**1,163,114**	**2,719,343**	**3,952,889**	**2,843,451**	**1,890,275**	**1,470,142**	**1,220,978**	**25,808,205**
# Customers		**12,993**	**13,068**	**13,798**	**13,910**	**13,734**	**13,512**	**13,764**	**13,810**	**13,832**	**13,566**	**13,403**	**12,805**	**13,516**

WEST TEXAS GAS UTILITY, LLC — **Schedule K-2**
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ADJUSTED TEST YEAR BILLING UNITS

WEST ZONE

	Reference	January	February	March	April	May	June	July	August	September	October	November	December	Total
								2023						
JURISDICTIONAL:														
Domestic:														
Mcf	Schedule K-5	51,095	49,713	28,100	18,113	19,040	6,519	8,663	9,788	9,481	19,960	30,327	50,604	301,402
# Customers	Schedule K-8	4,597	4,975	5,067	5,127	5,144	5,195	5,249	5,283	5,337	5,354	5,395	5,472	5,183
Non-Domestic:														
Public Authority														
Mcf	Schedule K-5	6,645	5,370	2,839	1,427	868	601	887	1,462	2,273	1,712	2,657	4,372	31,113
# Customers	Schedule K-8	137	138	138	138	138	137	138	138	138	138	137	142	138
Small Commercial														
Mcf	Schedule K-5	17,903	14,193	9,206	6,111	6,982	3,679	4,095	4,591	4,739	8,555	11,683	12,853	104,592
# Customers	Schedule K-8	685	394	394	399	402	402	403	407	415	421	423	427	431
Large Commercial														
Mcf	Schedule K-5	1,945	2,070	3,250	2,982	3,480	1,762	1,646	1,738	1,126	7,093	2,028	4,455	33,573
# Customers	Schedule K-8	10	10	10	10	10	10	11	11	10	10	10	10	10
Total Jurisdictional														
Mcf		**77,587**	**71,345**	**43,396**	**28,632**	**30,370**	**12,560**	**15,291**	**17,579**	**17,620**	**37,320**	**46,696**	**72,284**	**470,680**
# Customers		**5,429**	**5,517**	**5,609**	**5,674**	**5,694**	**5,744**	**5,801**	**5,839**	**5,900**	**5,923**	**5,965**	**6,051**	**5,762**
NON-JURISDICTIONAL:														
Public Authority														
Mcf	Schedule K-5	2,467	2,148	1,100	543	418	58	102	197	174	558	1,048	2,202	11,015
# Customers	Schedule K-8	7	7	6	6	6	5	5	6	6	6	6	6	6
Interstate														
Mcf	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
Small Commercial														
Mcf	Schedule K-5	35,747	23,341	26,324	23,470	23,236	23,060	18,539	13,683	10,602	29,195	82,722	68,666	378,586
# Customers	Schedule K-8	43	40	40	37	32	25	24	24	24	39	41	40	34
Large Commercial														
Mcf	Schedule K-5	3,034	2,643	3,181	2,867	3,046	1,523	2,593	1,968	2,170	3,955	3,264	4,668	34,911
# Customers	Schedule K-8	2	2	2	2	2	2	2	2	2	3	3	3	2
Irrigation														
Mcf	Schedule K-8	15,303	11,790	40,039	54,103	39,972	47,619	67,454	89,374	53,794	33,479	16,535	11,971	481,432
# Customers	Schedule K-8	251	245	255	253	251	251	256	250	255	244	238	230	248
Resale														
Mcf	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
Transportation														
Mcf	Schedule K-8	89,585	88,800	84,357	67,804	38,733	34,920	41,659	52,201	53,110	54,795	72,128	90,719	768,811
# Customers	Schedule K-8	4	4	4	4	4	4	4	4	4	4	4	4	4
Gathering														
Mcf	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Schedule K-8	-	-	-	-	-	-	-	-	-	-	-	-	-
Intercompany														
Mcf	Eliminated	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Eliminated	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Non-Jurisdictional														
Mcf		**146,136**	**128,721**	**155,002**	**148,786**	**105,405**	**107,180**	**130,347**	**157,423**	**119,851**	**121,982**	**175,697**	**178,226**	**1,674,755**
# Customers		**307**	**298**	**307**	**302**	**295**	**287**	**291**	**286**	**291**	**296**	**292**	**283**	**295**
TOTAL WEST ZONE														
Mcf		**223,723**	**200,066**	**198,398**	**177,418**	**135,776**	**119,740**	**145,637**	**175,001**	**137,471**	**159,302**	**222,392**	**250,510**	**2,145,435**
# Customers		**5,736**	**5,815**	**5,916**	**5,976**	**5,989**	**6,031**	**6,092**	**6,125**	**6,191**	**6,219**	**6,257**	**6,334**	**6,057**

WEST TEXAS GAS UTILITY, LLC
Test Period Ending December 31, 2023

Schedule K-3
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ADJUSTED TEST YEAR BILLING UNITS

SOUTH ZONE

		2023												
	Reference	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
JURISDICTIONAL:														
Domestic:														
Mcf	Schedule K-6	19,414	16,788	8,319	4,593	3,961	2,313	2,294	1,751	3,236	5,251	10,623	16,895	95,438
# Customers	Schedule K-9	3,371	3,381	3,375	3,359	3,349	3,348	3,347	3,338	3,312	3,316	3,338	3,323	3,346
Non-Domestic:														
Public Authority														
Mcf	Schedule K-6	9,012	8,479	4,187	2,997	2,762	1,736	1,227	2,287	1,627	3,464	5,240	7,447	50,465
# Customers	Schedule K-9	230	230	230	230	230	230	230	230	229	228	228	227	229
Small Commercial														
Mcf	Schedule K-6	10,556	10,386	6,843	5,400	6,391	4,040	5,035	4,968	5,842	6,252	9,090	9,697	84,501
# Customers	Schedule K-9	331	333	330	326	325	324	324	322	321	326	331	333	327
Large Commercial														
Mcf	Schedule K-6	1,938	1,736	1,747	1,261	1,226	1,041	918	1,116	898	2,454	7,086	5,635	27,056
# Customers	Schedule K-9	7	7	7	7	7	7	7	7	7	7	7	7	7
Total Jurisdictional														
Mcf		**40,921**	**37,389**	**21,096**	**14,250**	**14,341**	**9,130**	**9,473**	**10,122**	**11,602**	**17,422**	**32,039**	**39,673**	**257,460**
# Customers		**3,939**	**3,951**	**3,942**	**3,922**	**3,911**	**3,909**	**3,908**	**3,897**	**3,869**	**3,877**	**3,904**	**3,890**	**3,910**
NON-JURISDICTIONAL:														
Public Authority														
Mcf	Schedule K-6	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Schedule K-9	-	-	-	-	-	-	-	-	-	-	-	-	-
Interstate														
Mcf	Schedule K-9	-	-	-	-	-	-	-	-	-	-	-	-	-
# Customers	Schedule K-9	-	-	-	-	-	-	-	-	-	-	-	-	-
Small Commercial														
Mcf	Schedule K-6	49,045	45,715	48,772	46,678	43,891	48,528	52,664	52,131	54,322	50,878	58,331	54,831	605,785
# Customers	Schedule K-9	3	3	3	3	4	4	4	4	3	3	3	3	3
Large Commercial														
Mcf	Schedule K-6	15,318	14,802	2,602	623	182	57	1	1	2	376	8,124	14,284	56,371
# Customers	Schedule K-9	2	2	2	2	2	2	1	1	1	2	2	2	2
Irrigation														
Mcf	Schedule K-9	1,142	1,817	2,311	3,417	1,810	5,738	7,888	7,496	8,595	5,440	1,153	223	47,028
# Customers	Schedule K-9	32	33	32	29	30	30	28	30	30	30	26	27	30
Resale														
Mcf	Schedule K-9	0	0	0	0	0	0	0	0	0	0	0	0	0
# Customers	Schedule K-9	0	0	0	0	0	0	0	0	0	0	0	0	0
Transportation														
Mcf	Schedule K-9	1,038,590	965,310	1,005,706	892,993	1,018,672	1,022,764	1,045,685	1,003,523	956,455	1,009,934	968,139	881,216	11,808,984
# Customers	Schedule K-9	3	3	3	3	3	3	3	3	3	3	3	3	3
Gathering														
Mcf	Schedule K-9	0	0	0	0	0	0	0	0	0	0	0	0	0
# Customers	Schedule K-9	0	0	0	0	0	0	0	0	0	0	0	0	0
Intercompany														
Mcf	Eliminated	0	0	0	0	0	0	0	0	0	0	0	0	0
# Customers	Eliminated	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Non-Jurisdictional														
Mcf		**1,104,094**	**1,027,643**	**1,059,390**	**943,711**	**1,064,555**	**1,077,087**	**1,106,238**	**1,063,151**	**1,019,374**	**1,066,628**	**1,035,747**	**950,554**	**12,518,169**
# Customers		**40**	**41**	**40**	**37**	**39**	**39**	**36**	**38**	**37**	**38**	**34**	**35**	**38**
TOTAL SOUTH ZONE														
Mcf		**1,145,015**	**1,065,033**	**1,080,486**	**957,961**	**1,078,896**	**1,086,217**	**1,115,710**	**1,073,273**	**1,030,976**	**1,084,050**	**1,067,786**	**990,227**	**12,775,629**
# Customers		**3,979**	**3,992**	**3,982**	**3,959**	**3,950**	**3,948**	**3,944**	**3,935**	**3,906**	**3,915**	**3,938**	**3,925**	**3,948**

WEST TEXAS GAS UTILITY, LLC **Schedule K-4**
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WEATHER ADJUSTMENTS

NORTH ZONE -- Amarillo

	2023												
	January	February	March	April	May	June	July	August	September	October	November	December	Total
HEATING DEGREE DAYS:													
2023	748	589	484	264	28	5	-	-	3	198	448	671	3,438
10-Year Average	805	687	451	248	78	3	-	-	17	209	500	738	3,737
JURISDICTIONAL:													
Domestic:													
Mcf	114,649	120,818	74,935	37,778	29,101	16,630	11,866	17,095	13,684	23,030	69,335	96,953	625,873
# Customers	9,443	9,377	9,418	9,392	9,383	9,355	9,325	9,343	9,357	9,387	9,462	9,490	9,394
Use per Customer	12.14	12.88	7.96	4.02	3.10	1.78	1.27	1.83	1.46	2.45	7.33	10.22	66.62
Base Use per Customer	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59		1.59	1.59	17.44
Weather Sensitive Use	10.56	11.30	6.37	2.44	1.52	0.19	-	0.24	-	2.45	5.74	8.63	49.44
Weather Adjusted Use	11.47	12.28	6.92	2.65	1.65	0.21	-	0.27	-	2.67	6.24	9.38	53.74
Weather Adjusted Mcf	123,314	130,030	80,152	39,768	30,338	16,786	11,866	17,293	13,684	25,032	74,059	104,074	666,395
Non-Domestic:													
Public Authority													
Mcf	25,510	21,538	13,398	5,988	3,862	1,964	1,350	1,645	1,353	3,229	11,397	20,338	111,572
# Customers	382	368	368	369	370	368	368	369	368	370	371	372	370
Use per Customer	66.78	58.53	36.41	16.23	10.44	5.34	3.67	4.46	3.68	8.73	30.72	54.67	301.34
Base Use per Customer	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	4.29	51.42
Weather Sensitive Use	62.50	54.24	32.12	11.94	6.15	-	-	0.17	-	4.44	26.43	50.39	248.39
Weather Adjusted Use	67.93	58.96	34.92	12.98	6.69	-	-	0.19	-	4.83	28.73	54.77	269.99
Weather Adjusted Mcf	27,586	23,273	14,426	6,371	4,059	1,964	1,350	1,651	1,353	3,372	12,249	21,967	119,622
Small Commecial													
Mcf	31,337	31,737	22,473	10,320	7,411	3,829	3,739	(3,619)	12,285	6,019	16,812	28,902	171,244
# Customers	962	970	979	972	968	957	953	956	959	964	973	987	967
Use per Customer	32.58	32.72	22.95	10.62	7.66	4.00	3.92	(3.79)	12.81	6.24	17.28	29.28	177.15
Base Use per Customer	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	4.24	50.85
Weather Sensitive Use	28.34	28.48	18.72	6.38	3.42	-	-	-	8.57	2.01	13.04	25.05	134.00
Weather Adjusted Use	30.80	30.96	20.34	6.93	3.72	-	-	-	9.32	2.18	14.17	27.22	145.65
Weather Adjusted Mcf	33,707	34,139	24,066	10,859	7,699	3,829	3,739	(3,619)	12,999	6,187	17,915	31,051	182,571
Large Commercial													
Mcf	179	169	129	35	24	2	3	3	2	11	75	173	804
# Customers	4	4	5	4	4	4	4	4	4	4	4	4	4
Use per Customer	44.85	42.13	25.82	8.63	6.05	0.40	0.80	0.75	0.50	2.68	18.70	43.20	196.85
Base Use per Customer	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	7.35
Weather Sensitive Use	44.24	41.51	25.21	8.01	5.44	-	-	-	-	2.06	18.09	42.59	187.15
Weather Adjusted Use	48.08	45.12	27.40	8.71	5.91	-	-	-	-	2.24	19.66	46.29	203.42
Weather Adjusted Mcf	195	183	140	37	26	2	3	3	2	11	81	188	871
NON-JURISDICTIONAL:													
Public Authority													
Mcf	4,163	5,537	3,747	1,950	1,368	1,433	1,132	1,260	1,128	1,713	3,115	3,935	30,480
# Customers	(4)	6	7	7	7	6	6	7	7	7	7	7	6
Use per Customer	(1,040.68)	922.85	535.33	278.56	195.41	238.87	188.60	180.01	161.11	244.66	445.03	562.09	5,293.89
Base Use per Customer	192.15	192.15	192.15	192.15	192.15	192.15	192.15	192.15	192.15	192.15	192.15	192.15	2,305.79
Weather Sensitive Use	-	730.70	343.18	86.41	3.27	-	-	-	-	52.51	252.88	369.94	1,838.88
Weather Adjusted Use	-	794.23	373.02	93.92	3.55	-	-	-	-	57.07	274.87	402.10	1,998.75
Weather Adjusted Mcf	4,163	5,918	3,956	2,002	1,370	1,433	1,132	1,260	1,128	1,745	3,269	4,160	31,536
Small Commecial													
Mcf	238,441	222,132	214,518	168,108	252,919	179,734	172,753	205,192	258,788	238,985	263,835	266,254	2,681,659
# Customers	74	81	78	75	76	71	69	70	69	77	78	77	75
Use per Customer	3,222.17	2,742.37	2,750.23	2,241.44	3,327.89	2,531.46	2,503.66	2,931.32	3,750.55	3,103.70	3,382.49	3,457.84	35,955.20
Base Use per Customer	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	2,929.25	35,150.99
Weather Sensitive Use	292.92	-	-	-	398.64	-	-	-	821.30	174.45	453.25	528.59	2,669.16
Weather Adjusted Use	318.39	-	-	-	433.30	-	-	-	892.71	189.62	492.65	574.55	2,901.21
Weather Adjusted Mcf	240,325	222,132	214,518	168,108	255,553	179,734	172,753	205,192	263,715	240,153	266,908	269,793	2,698,884
Large Commercial													
Mcf	260,437	253,173	242,706	230,638	232,458	219,283	186,185	219,338	222,616	238,307	248,913	243,159	2,797,214
# Customers	6	6	5	6	6	5	5	6	6	7	7	7	6
Use per Customer	43,406.23	42,195.42	48,541.28	38,439.63	38,743.00	43,856.58	37,237.04	36,556.33	37,102.68	34,043.90	35,559.06	34,737.06	466,202.40
Base Use per Customer	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	38,688.16	464,257.91
Weather Sensitive Use	4,718.07	3,507.26	9,853.12	-	54.84	-	-	-	-	-	-	-	18,133.29
Weather Adjusted Use	5,128.26	3,812.18	10,709.75	-	59.61	-	-	-	-	-	-	-	19,709.80
Weather Adjusted Mcf	262,899	255,002	246,990	230,638	232,487	219,283	186,185	219,338	222,616	238,307	248,913	243,159	2,805,817

WEST TEXAS GAS UTILITY, LLC **Schedule K-5**
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WEATHER ADJUSTMENTS

	January	February	March	April	May	June	July	August	September	October	November	December	Total
WEATHER ADJUSTMENTS	711	456.2	239.9	81.7	11.7	0	0	0	5.9	91	320.7	506.7	
WEST ZONE -- Midland-Odessa							2023						
HEATING DEGREE DAYS:													
2023	550	448	250	105	1	-	-	-	-	92	325	487	2,258
10-Year Average	605	456	240	82	12	-	-	-	6	91	321	507	2,319
JURISDICTIONAL:													
Domestic:													
Mcf	49,956	48,704	27,582	17,858	18,761	6,519	8,663	9,758	9,461	19,667	29,764	49,514	296,207
# Customers	4,597	4,975	5,067	5,127	5,144	5,195	5,249	5,283	5,337	5,354	5,395	5,472	5,183
Use per Customer	10.87	9.79	5.44	3.48	3.65	1.25	1.65	1.85	1.77	3.67	5.52	9.05	57.15
Base Use per Customer	1.63	2.24	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	1.63	20.18
Weather Sensitive Use	9.24	7.55	3.81	1.85	2.02	-	-	0.22	0.14	2.04	3.89	7.42	38.17
Weather Adjusted Use	9.48	7.76	3.91	1.90	2.07	-	-	0.22	0.15	2.10	3.99	7.62	39.20
Weather Adjusted Mcf	51,095	49,713	28,100	18,113	19,040	6,519	8,663	9,788	9,481	19,960	30,327	50,604	301,402
Non-Domestic:													
Public Authority													
Mcf	6,505	5,264	2,799	1,424	868	601	887	1,457	2,248	1,701	2,621	4,293	30,667
# Customers	137	138	138	138	138	137	138	138	138	138	137	142	138
Use per Customer	47.48	38.14	20.28	10.32	6.29	4.39	6.42	10.56	16.29	12.33	19.13	30.23	222.09
Base Use per Customer	9.42	9.42	9.42	9.42	9.42	9.42	9.42	9.42	9.42	9.42	9.42	9.42	112.98
Weather Sensitive Use	38.06	28.73	10.87	0.90	-	-	-	1.15	6.87	2.91	9.72	20.82	120.02
Weather Adjusted Use	39.09	29.50	11.16	0.92	-	-	-	1.18	7.06	2.99	9.98	21.37	123.25
Weather Adjusted Mcf	6,645	5,370	2,839	1,427	868	601	887	1,462	2,273	1,712	2,657	4,372	31,113
Small Commecial													
Mcf	17,623	13,930	9,074	6,061	6,910	3,679	4,095	4,591	4,729	8,447	11,494	12,635	103,268
# Customers	685	394	394	399	402	402	403	407	415	421	423	427	431
Use per Customer	25.73	35.35	23.03	15.19	17.19	9.15	10.16	11.28	11.40	20.06	27.17	29.59	239.60
Base Use per Customer	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	125.97
Weather Sensitive Use	15.23	24.86	12.53	4.69	6.69	-	-	-	0.90	9.57	16.68	19.09	110.24
Weather Adjusted Use	15.64	25.52	12.87	4.82	6.87	-	-	-	0.92	9.82	17.12	19.60	113.19
Weather Adjusted Mcf	17,903	14,193	9,206	6,111	6,982	3,679	4,095	4,591	4,739	8,555	11,683	12,853	104,592
Large Commercial													
Mcf	1,933	2,055	3,204	2,943	3,428	1,762	1,646	1,738	1,126	6,946	2,014	4,377	33,172
# Customers	10	10	10	10	10	10	11	11	10	10	10	10	10
Use per Customer	193.29	205.46	320.41	294.27	342.81	176.20	149.65	157.96	112.61	694.61	201.40	437.72	3,262.78
Base Use per Customer	149.11	149.11	149.11	149.11	149.11	149.11	149.11	149.11	149.11	149.11	149.11	149.11	1,789.28
Weather Sensitive Use	44.18	56.35	171.30	145.16	193.70	-	-	-	-	545.50	52.29	288.61	1,497.11
Weather Adjusted Use	45.37	57.87	175.90	149.06	198.90	-	-	-	-	560.14	53.70	296.36	1,537.29
Weather Adjusted Mcf	1,945	2,070	3,250	2,982	3,480	1,762	1,646	1,738	1,126	7,093	2,028	4,455	33,573
NON-JURISDICTIONAL:													
Public Authority													
Mcf	2,407	2,096	1,075	532	411	58	102	196	173	547	1,025	2,148	10,769
# Customers	7	7	6	6	6	5	5	6	6	6	6	6	6
Use per Customer	343.80	299.39	179.17	88.73	68.53	11.58	20.44	32.63	28.88	91.10	170.75	358.02	1,794.88
Base Use per Customer	23.38	23.38	23.38	23.38	23.38	23.38	23.38	23.38	23.38	23.38	23.38	23.38	280.61
Weather Sensitive Use	320.42	276.00	155.78	65.35	45.15	-	-	9.25	5.50	67.72	147.37	334.63	1,427.16
Weather Adjusted Use	329.02	283.41	159.96	67.10	46.36	-	-	9.50	5.65	69.53	151.32	343.61	1,465.46
Weather Adjusted Mcf	2,467	2,148	1,100	543	418	58	102	197	174	558	1,048	2,202	11,015
Small Commecial													
Mcf	35,572	23,341	26,324	23,470	23,193	22,899	18,539	13,683	10,602	29,120	81,284	67,578	375,603
# Customers	43	40	40	37	32	25	24	24	24	39	41	40	34
Use per Customer	827.25	583.52	658.11	634.31	724.79	915.95	772.44	570.12	441.77	746.66	1,982.52	1,689.44	11,020.14
Base Use per Customer	675.07	675.07	675.07	675.07	675.07	675.07	675.07	675.07	675.07	675.07	675.07	675.07	8,100.83
Weather Sensitive Use	152.18	-	-	-	49.72	240.88	-	-	-	71.59	1,307.46	1,014.37	2,836.20
Weather Adjusted Use	156.27	-	-	-	51.05	247.35	-	-	-	73.52	1,342.54	1,041.59	2,912.32
Weather Adjusted Mcf	35,747	23,341	26,324	23,470	23,236	23,060	18,539	13,683	10,602	29,195	82,722	68,666	378,586
Large Commercial													
Mcf	3,008	2,628	3,152	2,846	3,020	1,523	2,593	1,968	2,170	3,932	3,259	4,627	34,726
# Customers	2	2	2	2	2	2	2	2	2	3	3	3	2
Use per Customer	1,504.10	1,314.00	1,576.05	1,422.95	1,510.15	761.45	1,296.45	983.80	1,085.15	1,310.73	1,086.40	1,542.23	14,369.50
Base Use per Customer	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	1,031.71	12,380.55
Weather Sensitive Use	472.39	282.29	544.34	391.24	478.44	-	-	-	-	279.02	54.69	510.52	3,012.92
Weather Adjusted Use	485.07	289.86	558.95	401.74	491.28	-	-	-	-	286.51	56.16	524.22	3,093.78
Weather Adjusted Mcf	3,034	2,643	3,181	2,867	3,046	1,523	2,593	1,968	2,170	3,955	3,264	4,668	34,911

WEST TEXAS GAS UTILITY, LLC **Schedule K-6**
Test Period Ending December 31, 2023 **Page 1 of 1**

WEATHER ADJUSTMENTS

SOUTH ZONE -- San Antonio Area

						2023							
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
HEATING DEGREE DAYS:													
2023	252	247	83	29	-	-	-	-	-	36	173	243	1,063
10-Year Average	371	275	108	26	1	-	-	-	-	29	163	286	1,259
JURISDICTIONAL:													
Domestic:													
Mcf	16,759	14,643	7,395	4,248	3,714	2,313	2,294	1,751	3,097	4,799	9,336	14,627	84,977
# Customers	3,371	3,381	3,375	3,359	3,349	3,348	3,347	3,338	3,312	3,316	3,338	3,323	3,346
Use per Customer	4.97	4.33	2.19	1.26	1.11	0.69	0.69	0.52	0.94	1.45	2.80	4.40	25.39
Base Use per Customer	0.71	0.90	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	8.70
Weather Sensitive Use	4.26	3.43	1.48	0.56	0.40	-	-	-	0.23	0.74	2.09	3.69	16.88
Weather Adjusted Use	5.05	4.07	1.76	0.66	0.47	-	-	-	0.27	0.87	2.47	4.38	20.00
Weather Adjusted Mcf	19,414	16,788	8,319	4,593	3,961	2,313	2,294	1,751	3,236	5,251	10,623	16,895	95,438
Non-Domestic:													
Public Authority													
Mcf	7,871	7,422	3,799	2,794	2,596	1,736	1,227	2,195	1,627	3,187	4,685	6,547	45,686
# Customers	230	230	230	230	230	230	230	230	229	228	228	227	229
Use per Customer	34.22	32.27	16.52	12.15	11.29	7.55	5.33	9.54	7.10	13.98	20.55	28.84	199.21
Base Use per Customer	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	7.38	88.58
Weather Sensitive Use	26.84	24.89	9.14	4.77	3.91	-	-	2.16	-	6.59	13.17	21.46	112.92
Weather Adjusted Use	31.80	29.48	10.82	5.65	4.63	-	-	2.56	-	7.81	15.60	25.42	133.79
Weather Adjusted Mcf	9,012	8,479	4,187	2,997	2,762	1,736	1,227	2,287	1,627	3,464	5,240	7,447	50,465
Small Commecial													
Mcf	9,700	9,561	6,563	5,335	6,170	4,040	5,035	4,968	5,697	6,055	8,462	8,979	80,564
# Customers	331	333	330	326	325	324	324	322	321	326	331	333	327
Use per Customer	29.30	28.71	19.89	16.37	18.98	12.47	15.54	15.43	17.75	18.57	25.56	26.96	246.25
Base Use per Customer	15.30	15.30	15.30	15.30	15.30	15.30	15.30	15.30	15.30	15.30	15.30	15.30	183.55
Weather Sensitive Use	14.01	13.41	4.59	1.07	3.69	-	-	-	2.45	3.28	10.27	11.67	64.44
Weather Adjusted Use	16.60	15.89	5.44	1.27	4.37	-	-	-	2.90	3.88	12.17	13.82	76.35
Weather Adjusted Mcf	10,556	10,386	6,843	5,400	6,391	4,040	5,035	4,968	5,842	6,252	9,090	9,697	84,501
Large Commercial													
Mcf	1,791	1,620	1,629	1,219	1,190	1,041	918	1,116	898	2,227	6,136	4,911	24,695
# Customers	7	7	7	7	7	7	7	7	7	7	7	7	7
Use per Customer	255.84	231.47	232.76	174.13	170.01	148.77	131.14	159.37	128.24	318.07	876.57	701.53	3,527.91
Base Use per Customer	141.88	141.88	141.88	141.88	141.88	141.88	141.88	141.88	141.88	141.88	141.88	141.88	1,702.59
Weather Sensitive Use	113.96	89.59	90.88	32.25	28.13	-	-	-	-	176.19	734.69	559.65	1,825.33
Weather Adjusted Use	135.02	106.14	107.67	38.20	33.33	-	-	-	-	208.74	870.43	663.05	2,162.58
Weather Adjusted Mcf	1,938	1,736	1,747	1,261	1,226	1,041	918	1,116	898	2,454	7,086	5,635	27,056
NON-JURISDICTIONAL:													
Public Authority													
Mcf													
# Customers													
Use per Customer													
Base Use per Customer													
Weather Sensitive Use													
Weather Adjusted Use													
Weather Adjusted Mcf													
Small Commecial													
Mcf	47,921	45,111	47,691	45,924	43,891	48,528	52,664	52,131	52,376	49,469	55,760	52,805	594,271
# Customers	3	3	3	3	4	4	4	4	3	3	3	3	3
Use per Customer	15,973.77	15,036.93	15,896.97	15,307.93	10,972.75	12,131.95	13,165.95	13,032.85	17,458.53	16,489.70	18,586.60	17,601.77	178,281.18
Base Use per Customer	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	13,947.32	167,367.85
Weather Sensitive Use	2,026.45	1,089.61	1,949.65	1,360.61	-	-	-	-	3,511.21	2,542.38	4,639.28	3,654.45	20,773.63
Weather Adjusted Use	2,400.85	1,290.93	2,309.86	1,612.00	-	-	-	-	4,159.94	3,012.11	5,496.43	4,329.64	24,611.77
Weather Adjusted Mcf	49,045	45,715	48,772	46,678	43,891	48,528	52,664	52,131	54,322	50,878	58,331	54,831	605,785
Large Commercial													
Mcf	12,931	12,497	2,199	528	156	57	1	1	2	320	6,860	12,059	47,610
# Customers	2	2	2	2	2	2	1	1	1	2	2	2	2
Use per Customer	6,465.70	6,248.25	1,099.25	264.00	78.15	28.55	1.00	1.00	2.00	159.85	3,430.00	6,029.35	27,205.83
Base Use per Customer	8.14	8.14	8.14	8.14	8.14	8.14	8.14	8.14	8.14	8.14	8.14	8.14	97.65
Weather Sensitive Use	6,457.56	6,240.11	1,091.11	255.86	70.01	-	-	-	-	151.71	3,421.86	6,021.21	23,709.45
Weather Adjusted Use	7,650.66	7,393.04	1,292.71	303.14	82.95	-	-	-	-	179.74	4,054.09	7,133.69	28,090.01
Weather Adjusted Mcf	15,318	14,802	2,602	623	182	57	1	1	2	376	8,124	14,284	56,371

WEST TEXAS GAS UTILITY, LLC **Schedule K-7**
Test Period Ending December 31, 2023 **Page 1 of 1**

UNADJUSTED TEST YEAR BILLING UNITS

NORTH ZONE

	2023												
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
JURISDICTIONAL:													
Domestic:													
Mcf	114,649	120,818	74,935	37,778	29,101	16,630	11,866	17,095	13,684	23,030	69,335	96,953	625,873
# Customers	9,443	9,377	9,418	9,392	9,383	9,355	9,325	9,343	9,357	9,387	9,462	9,490	9,394
Non-Domestic:													
Public Authority													
Mcf	25,510	21,538	13,398	5,988	3,862	1,964	1,350	1,645	1,353	3,229	11,397	20,338	111,572
# Customers	382	368	368	369	370	368	368	369	368	370	371	372	370
Small Commercial													
Mcf	31,337	31,737	22,473	10,320	7,411	3,829	3,739	(3,619)	12,285	6,019	16,812	28,902	171,244
# Customers	962	970	979	972	968	957	953	956	959	964	973	987	967
Large Commercial													
Mcf	179	169	129	35	24	2	3	3	2	11	75	173	804
# Customers	4	4	5	4	4	4	4	4	4	4	4	4	4
Total Jurisdictional													
Mcf	**171,676**	**174,262**	**110,935**	**54,121**	**40,398**	**22,424**	**16,958**	**15,124**	**27,324**	**32,289**	**97,618**	**146,365**	**909,493**
# Customers	**10,791**	**10,719**	**10,770**	**10,737**	**10,725**	**10,684**	**10,650**	**10,672**	**10,688**	**10,725**	**10,810**	**10,853**	**10,735**
NON-JURISDICTIONAL:													
Public Authority													
Mcf	4,163	5,537	3,747	1,950	1,368	1,433	1,132	1,260	1,128	1,713	3,115	3,935	30,480
# Customers	(4)	6	7	7	7	6	6	7	7	7	7	7	6
Interstate													
Mcf	31,818	24,145	39,127	46,424	46,939	20,793	50,572	81,449	66,299	45,792	37,603	26,979	517,941
# Customers	15	15	14	15	15	13	13	12	13	14	14	14	14
Small Commercial													
Mcf	238,441	222,132	214,518	168,108	252,919	179,734	172,753	205,192	258,788	238,985	263,835	266,254	2,681,659
# Customers	74	81	78	75	76	71	69	70	69	77	78	77	75
Large Commercial													
Mcf	260,437	253,173	242,706	230,638	232,458	219,283	186,185	219,338	222,616	238,307	248,913	243,159	2,797,214
# Customers	6	6	5	6	6	5	5	6	6	7	7	7	6
Irrigation													
Mcf	544,204	513,832	1,574,604	2,218,811	1,431,838	632,749	2,123,117	3,202,238	2,104,611	1,201,189	627,337	333,301	16,507,830
# Customers	2,096	2,225	2,908	3,053	2,888	2,716	3,005	3,029	3,034	2,719	2,469	1,831	2,664
Resale													
Mcf	149,273	119,108	202,577	188,532	96,242	41,770	172,676	188,488	118,945	70,290	103,622	87,214	1,538,737
# Customers	3	2	2	2	2	2	2	2	3	3	4	2	2
Transportation													
Mcf	103,786	87,419	71,435	41,081	26,828	21,861	(28,113)	15,855	16,265	30,993	57,021	83,686	528,118
# Customers	12	12	12	12	12	12	11	9	9	11	11	11	11
Gathering													
Mcf	-	1,717	1,702	25,656	24,485	22,911	24,064	23,741	21,833	27,203	21,164	15,406	209,882
# Customers	-	2	2	3	3	3	3	3	3	3	3	3	3
Intercompany													
Mcf	81,440	75,943	62,684	47,519	35,476	18,557	35,173	49,461	33,830	28,983	50,632	83,660	603,357
# Customers	16	16	16	16	16	17	16	16	16	16	16	16	16
Total Non-Jurisdictional													
Mcf	**1,413,562**	**1,303,006**	**2,413,100**	**2,968,719**	**2,148,553**	**1,159,091**	**2,737,557**	**3,987,023**	**2,844,316**	**1,883,455**	**1,413,243**	**1,143,594**	**25,415,219**
# Customers	**2,218**	**2,365**	**3,044**	**3,189**	**3,025**	**2,845**	**3,130**	**3,154**	**3,160**	**2,857**	**2,609**	**1,968**	**2,797**
TOTAL NORTH ZONE													
Mcf	**1,585,238**	**1,477,267**	**2,524,036**	**3,022,840**	**2,188,951**	**1,181,515**	**2,754,516**	**4,002,147**	**2,871,639**	**1,915,744**	**1,510,861**	**1,289,960**	**26,324,712**
# Customers	**13,009**	**13,084**	**13,814**	**13,926**	**13,750**	**13,529**	**13,780**	**13,826**	**13,848**	**13,582**	**13,419**	**12,821**	**13,532**
Check:	1,585,238	1,477,267	2,524,036	3,022,840	2,188,951	1,181,515	2,754,516	4,002,147	2,871,639	1,915,744	1,510,861	1,289,960	26,324,712
	13,009	13,084	13,814	13,926	13,750	13,529	13,780	13,826	13,848	13,582	13,419	12,821	13,532
Irrigation													
2019 Mcf	185,811	179,605	334,102	1,214,091	993,319	926,675	3,143,737	3,312,881	2,237,838	507,923	330,609	202,372	13,568,962
# Customers	1,776	1,784	2,028	3,003	3,101	3,071	3,362	3,393	3,372	2,654	2,271	1,873	2,641
2020 Mcf	173,611	146,065	852,458	1,520,033	2,032,634	2,919,373	3,061,538	2,928,028	1,591,133	900,775	391,323	184,650	16,701,620
# Customers	1,654	1,717	2,683	3,198	3,355	3,345	3,319	3,299	3,277	2,535	2,170	1,850	2,700
2021 Mcf	227,752	276,680	826,788	1,706,979	1,439,532	2,204,177	2,569,266	3,115,145	2,047,659	869,185	759,862	415,402	16,458,426
# Customers	1,836	1,859	2,580	3,120	3,169	3,248	3,254	3,263	3,240	2,696	2,608	2,353	2,769
2022 Mcf	329,496	361,510	1,236,316	2,112,751	2,104,935	2,258,431	2,938,452	3,281,153	2,218,380	1,060,842	695,046	405,851	19,003,163
# Customers	2,075	2,161	3,001	3,227	3,251	3,251	3,244	3,246	3,230	2,800	2,345	2,137	2,831
2023 Mcf	544,204	513,832	1,574,604	2,218,811	1,431,838	632,749	2,123,117	3,202,238	2,104,611	1,201,189	627,337	333,301	16,507,830
# Customers	2,096	2,225	2,908	3,053	2,888	2,716	3,005	3,029	3,034	2,719	2,469	1,831	2,664
Total Texas													
2019												14,143,815	14,143,815
													3,014
2020												17,324,457	17,324,457
													3,042
2021												17,013,348	17,013,348
													3,086
2022											4-Year Avg.	19,566,036	19,566,036
											17,011,914		3,123
2023													17,036,291
											-0.143%		2,942

WEST TEXAS GAS UTILITY, LLC | **Schedule K-8**
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UNADJUSTED TEST YEAR BILLING UNITS

WEST ZONE

	2023												
	January	February	March	April	May	June	July	August	September	October	November	December	Total
JURISDICTIONAL:													
Domestic:													
Mcf	49,956	48,704	27,582	17,858	18,761	6,519	8,663	9,758	9,461	19,667	29,764	49,514	296,207
# Customers	4,597	4,975	5,067	5,127	5,144	5,195	5,249	5,283	5,337	5,354	5,395	5,472	5,183
Non-Domestic:													
Public Authority													
Mcf	6,505	5,264	2,799	1,424	868	601	887	1,457	2,248	1,701	2,621	4,293	30,667
# Customers	137	138	138	138	138	137	138	138	138	138	137	142	138
Small Commecial													
Mcf	17,623	13,930	9,074	6,061	6,910	3,679	4,095	4,591	4,729	8,447	11,494	12,635	103,268
# Customers	685	394	394	399	402	402	403	407	415	421	423	427	431
Large Commercial													
Mcf	1,933	2,055	3,204	2,943	3,428	1,762	1,646	1,738	1,126	6,946	2,014	4,377	33,172
# Customers	10	10	10	10	10	10	11	11	10	10	10	10	10
Total Jurisdictional													
Mcf	**76,016**	**69,952**	**42,659**	**28,285**	**29,968**	**12,560**	**15,291**	**17,544**	**17,565**	**36,762**	**45,894**	**70,819**	**463,313**
# Customers	**5,429**	**5,517**	**5,609**	**5,674**	**5,694**	**5,744**	**5,801**	**5,839**	**5,900**	**5,923**	**5,965**	**6,051**	**5,762**
NON-JURISDICTIONAL:													
Public Authority													
Mcf	2,407	2,096	1,075	532	411	58	102	196	173	547	1,025	2,148	10,769
# Customers	7	7	6	6	6	5	5	6	6	6	6	6	6
Interstate													
Mcf													
# Customers													
Small Commercial													
Mcf	35,572	23,341	26,324	23,470	23,193	22,899	18,539	13,683	10,602	29,120	81,284	67,578	375,603
# Customers	43	40	40	37	32	25	24	24	24	39	41	40	34
Large Commercial													
Mcf	3,008	2,628	3,152	2,846	3,020	1,523	2,593	1,968	2,170	3,932	3,259	4,627	34,726
# Customers	2	2	2	2	2	2	2	2	2	3	3	3	2
Irrigation													
Mcf	15,303	11,790	40,039	54,103	39,972	47,619	67,454	89,374	53,794	33,479	16,535	11,971	481,432
# Customers	251	245	255	253	251	251	256	250	255	244	238	230	248
Resale													
Mcf													
# Customers													
Transportation													
Mcf	89,585	88,800	84,357	67,804	38,733	34,920	41,659	52,201	53,110	54,795	72,128	90,719	768,811
# Customers	4	4	4	4	4	4	4	4	4	4	4	4	4
Gathering													
Mcf													
# Customers													
Intercompany													
Mcf													
# Customers													
Total Non-Jurisdictional													
Mcf	**145,874**	**128,654**	**154,948**	**148,754**	**105,330**	**107,018**	**130,347**	**157,421**	**119,850**	**121,874**	**174,230**	**177,042**	**1,671,342**
# Customers	**307**	**298**	**307**	**302**	**295**	**287**	**291**	**286**	**291**	**296**	**292**	**283**	**295**
TOTAL WEST ZONE													
Mcf	**221,890**	**198,606**	**197,606**	**177,039**	**135,298**	**119,579**	**145,637**	**174,965**	**137,414**	**158,635**	**220,124**	**247,861**	**2,134,655**
# Customers	**5,736**	**5,815**	**5,916**	**5,976**	**5,989**	**6,031**	**6,092**	**6,125**	**6,191**	**6,219**	**6,257**	**6,334**	**6,057**
Check:	221,890	198,606	197,606	177,039	135,298	119,579	145,637	174,965	137,414	158,635	220,124	247,861	2,134,655
	5,736	5,815	5,916	5,976	5,989	6,031	6,092	6,125	6,191	6,219	6,257	6,334	6,057
Irrigation													
2019 Mcf	6,301	18,465	26,636	61,941	51,707	49,809	85,931	98,029	59,979	32,629	7,221	4,040	502,687
# Customers	334	332	349	352	352	343	349	350	341	322	301	293	335
2020 Mcf	7,642	6,834	21,985	46,665	61,847	67,979	99,496	104,602	67,209	40,007	12,120	12,341	548,725
# Customers	303	305	293	307	313	310	313	321	317	301	297	294	306
2021 Mcf	11,147	12,711	36,347	53,281	60,675	48,197	47,691	72,590	76,577	40,644	27,792	8,648	496,299
# Customers	287	279	296	303	291	277	266	285	290	280	267	254	281
2022 Mcf	5,227	13,405	42,403	65,136	62,823	66,309	87,406	72,386	34,354	17,284	7,489	4,233	478,455
# Customers	256	263	269	278	266	261	260	260	245	241	238	238	256
2023 Mcf	15,303	11,790	40,039	54,103	39,972	47,619	67,454	89,374	53,794	33,479	16,535	11,971	481,432
# Customers	251	245	255	253	251	251	256	250	255	244	238	230	248

WEST TEXAS GAS UTILITY, LLC | **Schedule K-9**
Test Period Ending December 31, 2023 | **Page 1 of 1**

UNADJUSTED TEST YEAR BILLING UNITS

SOUTH ZONE

	2023												
	January	February	March	April	May	June	July	August	September	October	November	December	Total
JURISDICTIONAL:													
Domestic:													
Mcf	16,759	14,643	7,395	4,248	3,714	2,313	2,294	1,751	3,097	4,799	9,336	14,627	84,977
# Customers	3,371	3,381	3,375	3,359	3,349	3,348	3,347	3,338	3,312	3,316	3,338	3,323	3,346
Non-Domestic:													
Public Authority													
Mcf	7,871	7,422	3,799	2,794	2,596	1,736	1,227	2,195	1,627	3,187	4,685	6,547	45,686
# Customers	230	230	230	230	230	230	230	230	229	228	228	227	229
Small Commercial													
Mcf	9,700	9,561	6,563	5,335	6,170	4,040	5,035	4,968	5,697	6,055	8,462	8,979	80,564
# Customers	331	333	330	326	325	324	324	322	321	326	331	333	327
Large Commercial													
Mcf	1,791	1,620	1,629	1,219	1,190	1,041	918	1,116	898	2,227	6,136	4,911	24,695
# Customers	7	7	7	7	7	7	7	7	7	7	7	7	7
Total Jurisdictional													
Mcf	**36,121**	**33,246**	**19,386**	**13,597**	**13,670**	**9,130**	**9,473**	**10,030**	**11,318**	**16,267**	**28,619**	**35,064**	**235,922**
# Customers	**3,939**	**3,951**	**3,942**	**3,922**	**3,911**	**3,909**	**3,908**	**3,897**	**3,869**	**3,877**	**3,904**	**3,890**	**3,910**
NON-JURISDICTIONAL:													
Public Authority													
Mcf													
# Customers													
Interstate													
Mcf													
# Customers													
Small Commercial													
Mcf	47,921	45,111	47,691	45,924	43,891	48,528	52,664	52,131	52,376	49,469	55,760	52,805	594,271
# Customers	3	3	3	3	4	4	4	4	3	3	3	3	3
Large Commercial													
Mcf	12,931	12,497	2,199	528	156	57	1	1	2	320	6,860	12,059	47,610
# Customers	2	2	2	2	2	2	1	1	1	2	2	2	2
Irrigation													
Mcf	1,142	1,817	2,311	3,417	1,810	5,738	7,888	7,496	8,595	5,440	1,153	223	47,028
# Customers	32	33	32	29	30	30	28	30	30	30	26	27	30
Resale													
Mcf													
# Customers													
Transportation													
Mcf	1,038,590	965,310	1,005,706	892,993	1,018,672	1,022,764	1,045,685	1,003,523	956,455	1,009,934	968,139	881,216	11,808,984
# Customers	3	3	3	3	3	3	3	3	3	3	3	3	3
Gathering													
Mcf													
# Customers													
Intercompany													
Mcf													
# Customers													
Total Non-Jurisdictional													
Mcf	**1,100,584**	**1,024,734**	**1,057,906**	**942,862**	**1,064,529**	**1,077,087**	**1,106,238**	**1,063,151**	**1,017,427**	**1,065,162**	**1,031,911**	**946,303**	**12,497,894**
# Customers	**40**	**41**	**40**	**37**	**39**	**39**	**36**	**38**	**37**	**38**	**34**	**35**	**38**
TOTAL SOUTH ZONE													
Mcf	**1,136,706**	**1,057,980**	**1,077,292**	**956,459**	**1,078,199**	**1,086,217**	**1,115,710**	**1,073,181**	**1,028,746**	**1,081,429**	**1,060,530**	**981,367**	**12,733,815**
# Customers	**3,979**	**3,992**	**3,982**	**3,959**	**3,950**	**3,948**	**3,944**	**3,935**	**3,906**	**3,915**	**3,938**	**3,925**	**3,948**
Check:													
Mcf	1,136,706	1,057,980	1,077,292	956,459	1,078,199	1,086,217	1,115,710	1,073,181	1,028,746	1,081,429	1,060,530	981,367	12,733,815
# Customers	3,979	3,992	3,982	3,959	3,950	3,948	3,944	3,935	3,906	3,915	3,938	3,925	3,948

Irrigation

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2019 Mcf	5,295	5,009	7,983	5,268	4,763	6,615	5,008	11,529	7,139	6,136	3,580	3,841	72,166
# Customers	38	40	44	38	40	43	39	39	35	34	32	37	38
2020 Mcf	3,891	2,629	4,101	3,710	4,680	6,585	10,041	10,130	9,036	11,027	4,862	3,420	74,112
# Customers	34	36	36	39	37	38	36	34	34	35	32	36	36
2021 Mcf	778	1,096	4,887	7,777	2,008	5,783	2,910	7,763	10,037	6,299	4,329	4,955	58,623
# Customers	32	34	46	42	31	40	34	34	35	34	32	32	36
2022 Mcf	2,805	3,893	8,787	11,523	8,737	12,745	12,076	6,809	8,294	5,314	2,803	633	84,418
# Customers	33	37	40	42	39	39	37	38	33	34	32	28	36
2023 Mcf	1,142	1,817	2,311	3,417	1,810	5,738	7,888	7,496	8,595	5,440	1,153	223	47,028
# Customers	32	33	32	29	30	30	28	30	30	30	26	27	30

SCHEDULE WORKPAPERS

Schedule Workpapers are voluminous and are being provided in electronic format.

TESTIMONY WORKPAPERS

Testimony Workpapers are voluminous and are being provided in electronic format.