Southwest Gas Corporation

DOCKET NO. G-01551A-19-0055

2019 General Rate Case

Application
Tariff Sheets

Vol. 1 of 3

May 1, 2019

Application

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
Bob Burns, Chairman
Boyd Dunn
Andy Tobin
Sandra Kennedy
Justin Olson

In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Arizona Operations	DOCKET NO. G-01551A-19-0055

APPLICATION

1. Introduction.

Southwest Gas Corporation (Southwest Gas or Company) hereby submits to the Arizona Corporation Commission (Commission) its application requesting approval of an increase in the retail natural gas utility service rates in its Arizona rate jurisdiction due to a revenue deficiency of approximately $57 million. As set forth more fully in the supporting testimony, it has been approximately three years since the Company last filed a general rate case, and currently effective rates are based upon the level of operating expenses and capital investments made by the Company prior to November 30, 2015. The Company proposes to increase revenues by approximately 8.1 percent to adequately recover its current level of operating expenses and to begin recovering the costs associated with the significant capital investments the Company has made in its natural gas distribution system since its last rate case, which are not presently included in rates. Additionally, the Company's cost of service must be updated to fully reflect the impact of the Tax Cuts and Jobs Act (Tax Reform), which reduced the corporate income tax rate from 35 percent to 21 percent. As discussed in further detail below and in the accompanying testimony, Southwest Gas is also seeking authority to implement an infrastructure program and associated cost recovery mechanism for the enhanced evaluation and replacement of certain plastic pipe that is not performing as expected; authority to incorporate Renewable Natural Gas (RNG) into its gas supply portfolio; and various tariff changes.

This application is based upon and supported by the material facts, points and authorities, and all other information contained herein, the supporting testimony and schedules submitted herewith, and such other matters as may be presented to the Commission at the time of any hearing on this application. In support of its application, Southwest Gas states as follows:

2. Applicant.

2.1 Southwest Gas is a corporation in good standing under the laws of the state of Arizona, and is a corporation duly organized, validly existing, and qualified to transact intrastate business.

2.2 Southwest Gas' corporate offices are located at 5241 Spring Mountain Road, P.O. Box 98510, Las Vegas, Nevada 89193-8510. Communications regarding this application should be addressed to:

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2.3 Southwest Gas is a public utility subject to the jurisdiction of the Commission pursuant to Article XV of the Arizona Constitution and the applicable provisions of Title 40 of the Arizona Revised Statutes (A.R.S.). Southwest Gas is engaged in the retail distribution, transportation and sale of natural gas for domestic, commercial, agricultural and industrial uses. Southwest Gas currently serves approximately 2.0 million customers in Arizona, California, and Nevada. Approximately 54 percent, or 1.1 million, of the Company's customers are located in the state of Arizona, including portions of Cochise, Gila, Graham, Greenlee, La Paz, Maricopa, Mohave, Pima, Pinal and Yuma counties. For operational purposes, Southwest Gas' central Arizona division is headquartered in Phoenix and its southern Arizona division is headquartered in Tucson.

3. Authority.

Southwest Gas submits this application pursuant to Article XV, Sections 3 and 14, of the Arizona Constitution, Sections 40-250 and 40-251 of the A.R.S., as well as other applicable provisions of A.R.S. Title 40, and Section R14-2-103 of the Arizona Administrative Code (A.A.C.). The Application consists of three volumes, organized as follows: Volume I contains the application, proposed tariff sheets and current tariff sheets; Volume II contains the prepared direct testimony supporting the relief requested herein; and Volume III contains supporting schedules. Southwest Gas is a Class A utility, as defined by A.A.C. R14-2-103. Accordingly, the schedules required by A.A.C. R14-2-103 are included herewith as Volume III of this application.

4. Brief Overview of Application.

4.1 Southwest Gas' requested revenue increase is necessary to maintain and provide safe and reliable natural gas service to its Arizona customers at a level they both expect and are entitled to receive. Southwest Gas' application includes only those proposals it believes necessary to provide safe and reliable service at reasonable rates.

4.2 Southwest Gas requests authorization to increase its retail rates in Arizona to recover its revenue deficiency of approximately $57 million.

4.3 In addition to Southwest Gas' request for authority to increase its retail natural gas rates, the Company requests authority to implement a new infrastructure program which involves the proactive assessment and, if necessary, replacement of certain 7000 and 8000 Driscopipe, along with the associated cost recovery mechanism.

4.4 The Company also seeks approval of an RNG Program to incorporate RNG into its gas supply portfolio and include the associated costs of those purchases, as well as any revenue from the sale of environmental attributes that may be associated with the RNG, in the Company's Purchased Gas Cost Adjustment Provision.

4.5 Finally, Southwest Gas proposes minor tariff changes to reflect current business practices and Pipeline and Hazardous Materials Safety Administration (PHMSA) rule changes, as well as to correct minor inconsistencies and incorporate non-substantive housekeeping edits.

5. Request for Authority to Increase Rates.

5.1 Southwest Gas' current rates and charges were approved by the Commission in Decision No. 76069, based on a test year ended November 30, 2015.

5.2 As set forth more fully in the supporting testimony, it has been approximately three years since the Company last filed a general rate case, and currently effective rates are based upon the level of operating expenses and capital investments made by the Company prior to November 30, 2015. Although Southwest Gas has efficiently managed operating expenses over the past three years, it has invested more than $667 million into its Arizona gas distribution system. Authorized revenues therefore need to be updated to reflect overall changes in the level of operating expenses currently being experienced by the Company and to reflect the significant capital investments the Company has made in its natural gas distribution system since its last rate case, which are not presently included in rates.

5.3 Southwest Gas also proposes adjustments related to the enactment of Tax Reform which went into effect after the Company's last general rate case and reduced the corporate income tax rate from 35 percent to 21 percent. The Company's cost of service must therefore be updated to fully reflect the impact of Tax Reform.

5.4 Southwest Gas' request is based upon a test period ended January 31, 2019, adjusted for changes in revenues and expenses, including its cost of capital, that are known and measurable with reasonable accuracy at the time of filing. Southwest Gas requests authority to increase rates to achieve an increase in total revenues of approximately $57 million to produce the Company's requested 5.98 percent fair value rate of return.

5.5 Southwest Gas also proposes adjustments related to events that have occurred, or will occur, after the end of the test period. By including these proposed adjustments in its application, the Company presents a more accurate level of costs and expenses that will be incurred once the rates approved in this proceeding become effective. The proposed adjustments include the Company's 2019 wage increase and within-grade movement; software projects expected to close through December 31, 2019 and non-revenue producing plant additions anticipated through July 31, 2019; and the plant and annualized operations & maintenance (O&M) expense related to the Liquified Natural Gas (LNG) storage facility being constructed in Tucson.

5.6 Southwest Gas' requested revenue increase is based upon a 10.30 percent cost of common equity capital relative to the Company's actual capital structure at the end of the test period, consisting of a common equity ratio of 51.1 percent. Southwest Gas submits that the recommended cost of common equity capital represents a conservative estimate of investor expectations given recent financial market conditions, that is in line with the Company's proxy group.

5.7 The proposed increase in revenues is necessary to provide Southwest Gas a reasonable opportunity to earn a fair and reasonable rate of return on the fair value of its Arizona investments in order to attract the capital necessary to ensure that it can continue to provide reliable service to present and future Arizona customers at reasonable rates. Additional information regarding Southwest Gas' proposed rate increase is provided in the supporting testimony and schedules accompanying this application.

6. Request for Approval of 7000/8000 Pipe Replacement Program.

6.1 As a natural gas distribution company, Southwest Gas takes pipeline safety very seriously and is dedicated to providing safe and reliable service to its customers. An important part of providing that safe and reliable service is developing infrastructure proposals that respond to both operational concerns and customer needs.

6.2 In prior proceedings, Southwest Gas worked collaboratively with the Commission and other parties to develop infrastructure recovery mechanisms for the Company's Customer Owned Yard Line (COYL) and Vintage Steel Pipe (VSP) Replacement programs. In this proceeding, Southwest Gas requests authority to implement its proposed 7000/8000 Pipe Replacement Program which involves the enhanced assessment and replacement, as necessary, of certain 7000 and 8000 Driscopipe installed in the Company's Arizona distribution system prior to 2001. Southwest Gas has observed material degradation in its 7000 and 8000 Driscopipe inventory, including some degradation that has resulted in leakage. While the Company has efforts in place to evaluate the degradation when pipe is exposed during normal field excavations, the proposed 7000/8000 Pipe Replacement Program will allow the Company to proactively assess a larger portion of its 7000 and 8000 Driscopipe inventory through enhanced field inspections. This Program will also allow the Company to replace 7000 and 8000 Driscopipe, as necessary, before the degradation results in a leak.

6.3 Cost recovery for the proposed 7000/8000 Pipe Replacement Program is structured in a manner similar to the first phase of the COYL program, which was approved by the Commission in Southwest Gas' 2010 general rate case. In that case, the Company was authorized a certain level of O&M expense in base rates to leak survey COYLs and if they were found to be leaking, the Company would offer the customer the opportunity to relocate the COYL at no direct cost to the customer.

7. Request for Approval of RNG Program.

7.1 RNG is biogas that is cleaned or upgraded to pipeline quality gas and can be injected into and distributed through an existing natural gas delivery system. RNG is considered a carbon-neutral fuel and offers even greater benefits when it is produced from organic waste that would otherwise decay and create methane emissions.

7.2 There are many sources of biogas in Arizona, including wastewater treatment plants, dairies, and landfills. Many wastewater treatment plants and landfills in Arizona capture biogas to prevent the direct release of the harmful greenhouse gas, methane, into the atmosphere. However, most Arizona biogas is not currently cleaned or upgraded to RNG and, therefore, is not capable of being injected into an existing natural gas delivery system. Further, the RNG that is currently being produced in Arizona is likely being transported to California where it qualifies under the Federal EPA Renewable Fuel Standard Program and California's Low Carbon Fuel Standard Program.

7.3 To develop RNG resources and keep the supply in the state, the Company seeks approval to of an RNG Program that would allow the Company to meet up to 1 percent of its forecasted annual Arizona retail sales with RNG purchases by 2025, 2 percent by 2030, and 3 percent by 2035. As part of the RNG Program, the Company would include the cost of the RNG purchases in the Company's Purchased Gas Cost Adjustment Provision.

8. Miscellaneous Items.

Bill Impact

8.1 Southwest Gas is mindful of the impact rate increases have on its customers and does its best to implement cost saving strategies to minimize increases for its customers. As discussed above and in the supporting testimony, the Company has effectively managed its costs in the three years since its last general rate case filing in 2016. However, the Company has also invested more than $667 million in its Arizona natural gas system in that same timeframe.

8.2 If the Company's application is accepted as filed, the proposed average monthly single family residential bill would increase $4.75 a month, resulting in an average monthly bill of approximately $40.91.

Rate Design

8.3 Southwest Gas proposes the same rate design approved by the Commission in the Company's last general rate case – consisting of a monthly basic service charge and a volumetric rate that captures both delivery charges and gas costs. Southwest Gas' proposed rate design strives to accomplish four objectives: 1) the fair and equitable recovery of costs; 2) rates that work well in concert with the Delivery Charge Adjustment; 3) customer acceptance and understandability; and 4) the effect of the rate design on the promotion of the Company's energy efficiency and conservation efforts. Moreover, the revenue stability offered by the Company's decoupled rate structure affords it the opportunity to recover its revenue deficiency in variable charges. As a result, Southwest Gas' proposed rate design maintains basic service charges at their current levels – for example, the single family residential basic service charge is proposed to remain at $10.70.

Witnesses – Prepared Direct Testimony

8.4 Southwest Gas' application and the requests made herein are supported by the prepared direct testimony and exhibits of the following Company witnesses, all of which are included in Volume II of the application:

- **Matthew D. Derr** provides a summary of the Company's application for rate relief, testimony regarding the Company's currently authorized infrastructure recovery mechanisms, and supports, from a ratemaking perspective, the Company's proposed 7000/8000 Pipe Replacement Program. Mr. Derr also supports the Company's proposed tariff changes.
- **Byron C. Williams** provides testimony supporting~~,~~ the Company's calculation of the federal income tax expense and the impact of Tax Reform on the calculation of the federal income taxes, the Company's calculation and treatment of excess accumulated deferred income taxes, and application of the Modified Business Tax.
- **Kevin M. Lang** provides testimony supporting, from an operations perspective, the Company's proposed 7000/8000 Pipe Replacement Program.
- **John R. Olenick** provides testimony supporting the Company's proposed RNG Program.
- **Carla D. Ayala** provides testimony supporting the methodology used by the Company to develop billing determinants for the test period under present rates, and Company's proposed adjustments to test year bills and volumes, including its proposed weather normalization adjustment. Ms. Ayala also sponsors schedules and work papers supporting the Company's billing determinants for the test year.

- **Kristien M. Tary** sponsors the Company's embedded class cost of service study and supports the Company's proposed rate design.
- **Dane A. Watson** sponsors the removal cost allocation study conducted in compliance with Decision No. 76069 in Docket No. G-01551A-16-0107. Mr. Watson is a Certified Depreciation Professional and Partner in Alliance Consulting Group and was engaged by Southwest Gas to conduct the required removal cost allocation study.
- **Randi L. Cunningham** provides testimony supporting the overall results of operations in Southwest Gas' Arizona rate jurisdiction, including the determination of revenue deficiency. Ms. Cunningham identifies and explains the major reasons and underlying causes of the revenue deficiency and sponsors various schedules and work papers supporting the Company's requested revenue requirement, as well as various revenue requirement schedules. Ms. Cunningham also provides testimony supporting the Company's methodology for determining cost responsibility and allocation and sponsors various schedules and work papers supporting the Company's operating expense and rate base adjustments, as well as certain financial and statistical statements and projections. Finally, Ms. Cunningham discusses the appropriate fair value rate of return to apply to incremental capital projects.
- **Theodore K. Wood** provides testimony supporting the overall rate of return requested in this proceeding. Mr. Wood supports the Company's requested capital structure and embedded cost of long-term debt used for determining the appropriate cost of capital, including various schedules and supporting work papers. Mr. Wood also discusses the importance of the Company's overall rate of return on the Company's bond ratings and financial profile as well as the inequities associated with using the fair value rate of return from a utility's last general rate case when calculating the revenue requirement associated with incremental investment in facilities.

- **Robert B. Hevert** provides testimony supporting the Company's proposed cost of common equity. Mr. Hevert is a Partner at ScottMadden, Inc., and was engaged by Southwest Gas to perform an analysis and provide a recommendation concerning the Company's cost of common equity, an analysis of the methodology used by the Company to calculate fair value rate base, and a recommendation concerning the Company's fair value rate of return.

9. Conclusion.

9.1 Southwest Gas believes that Commission approval of the proposed rate increase will result in just and reasonable rates.

9.2 Southwest Gas further submits that approval of this application as proposed will provide the Company with an opportunity to earn a reasonable rate of return on the fair value of its Arizona properties commensurate with other similarly situated natural gas utilities.

WHEREFORE, Southwest Gas respectfully requests that the Commission issue a special order pursuant to A.A.C. R14-3-101.C, to establish notice, filing, discovery and hearing procedures, and that upon conclusion of the hearing, the Commission issue a final order:

1. Authorizing a retail natural gas service rate increase in Southwest Gas' Arizona rate jurisdiction of $57 million annually, based upon the fair value of the Company's Arizona properties and a test year ended January 31, 2019;
2. Approving the Company's proposed 7000/8000 Pipe Replacement Program as set forth herein;
3. Approving the Company's proposed RNG Program as set forth herein;
4. Approving the Company's proposed rate design;
5. Approving the Company's proposed revisions to its Arizona Gas Tariff; and

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6. For any other relief the Commission deems just and reasonable based upon the requests contained within this filing.

Dated this 1st day of May 2019.

Respectfully submitted,

SOUTHWEST GAS CORPORATION

Catherine M. Mazzeo

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Attorney for Southwest Gas Corporation

I hereby certify that I have on this 1st day of May 2019, electronically filed the foregoing with the Arizona Corporation Commission using the ACC Portal. On the 2nd day of May 2019, an original and 8 copies will be hand delivered to the Commission's Docket Control and to the following:

Jordy Fuentes
Director, Residential Utility Consumer Office
1110 West Washington Street, Suite #220
Phoenix, AZ 85007

By: ______________________________

Tariff sheet

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RULES

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Las Vegas, Nevada 89193-8510
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Arizona Division Canceling ____________ A.C.C. Sheet No. ____________

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/

Description	Delivery Charge	3/ Rate Adjustment	Monthly Gas Cost	Currently Effective Tariff Rate	
G-5 – Single-Family Residential Gas Service					
Basic Service Charge per Month	$ 10.70			$ 10.70	
Commodity Charge per Therm:					
All Usage	$ .93493	($ .01239)	$ .35399	$ 1.27653	I
G-6 – Multi-Family Residential Gas Service					
Basic Service Charge per Month	$ 9.70			$ 9.70	
Commodity Charge per Therm:					
All Usage	$ 1.05686	($ .01239)	$ .35399	$ 1.39846	I
G-10 – Single-Family Low Income Residential Gas Service					
Basic Service Charge per Month	$ 7.50			$ 7.50	
Commodity Charge per Therm:					
Summer (May–October):					
All Usage	$ .93493	($ .03328)	$ .35399	$ 1.25564	I
Winter (November–April):					
First 150 Therms	.55488	($ .03328)	$ .35399	.87559	I
Over 150 Therms	$ .93493	($ .03328)	$ .35399	$ 1.25564	I
G-11 – Multi-Family Low Income Residential Gas Service					
Basic Service Charge per Month	$ 7.50			$ 7.50	
Commodity Charge per Therm:					
Summer (May–October):					
All Usage	$ 1.05686	($ .03328)	$ .35399	$ 1.37757	I
Winter (November–April):					
First 150 Therms	.54025	($ .03328)	$ .35399	.86096	I
Over 150 Therms	$ 1.05686	($ .03328)	$ .35399	$ 1.37757	I
G-15 – Special Residential Gas Service for Air Conditioning					
Basic Service Charge per Month	$ 10.70			$ 10.70	
Commodity Charge per Therm:					
Summer (May–October):					
First 15 Therms	$ .93493	($ .02996)	$ .35399	$ 1.25896	I
Over 15 Therms	.15422	($ .02996)	$ .35399	.47825	I
Winter (November–April):					
All Usage	$ .93493	($ .02996)	$ .35399	$ 1.25896	I
G-20 – Master-Metered Mobile Home Park Gas Service					
Basic Service Charge per Month	$ 66.00			$ 66.00	
Commodity Charge per Therm:					
All Usage	$ .51948	($ .01452)	$ .35399	$ .85895	I

Issued On ____________
Docket No. G-01551A-19-0055

Issued by
Justin Lee Brown
Senior Vice President

Effective ____________
Decision No. ____________

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/
(Continued)

Description	Delivery Charge	3/ Rate Adjustment	Monthly Gas Cost	Currently Effective Tariff Rate	
G-25– General Gas Service					
Basic Service Charge per Month:					
Small	$ 27.50			$ 27.50	
Medium	43.50			43.50	
Large-1	80.00			80.00	
Large-2	470.00			470.00	
Transportation Eligible	950.00			950.00	
Commodity Charge per Therm:					
Small, All Usage	$ 1.01717	($ .02783)	$ .35399	$ 1.34333	I
Medium, All Usage	.48608	(.02783)	.35399	.81224	I
Large-1, All Usage	.43783	(.02783)	.35399	.76399	I
Large-2, All Usage	.32700	(.02783)	.35399	.65316	I
Transportation Eligible	.12480	(.02996)	.35399	.44883	I
Demand Charge per Month–					
Transportation Eligible:					
Demand Charge 4/	$ .0089287			$ .089287	I
G-30– Optional Gas Service					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 27.				
Commodity Charge per Therm:					
All Usage	As specified on A.C.C. Sheet No. 28.				
G-40– Air Conditioning Gas Service					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 32.				
Commodity Charge per Therm:					
All Usage	$ .15422	($ .02996)	$ .35399	$ .47825	I
G-45– Street Lighting Gas Service					
Commodity Charge per Therm of Rated Capacity:					
All Usage	$ .87963	($ .02996)	$ .35399	$ 1.20366	I
G-50– Compression Gas Service					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 36.				
Commodity Charge per Therm:					
All Usage	As specified on A.C.C. Sheet No. 36.				
G-55– Gas Service for Compression 5/ on Customer's Premises					
Basic Service Charge per Month:					
Small	$ 27.50			$ 27.50	
Large	250.00			250.00	
Residential	10.70			10.70	
Commodity Charge per Therm:					
All Usage	$ .24048	($ .02996)	$ .35399	$ .56451	I
G-60– Electric Generation Gas Service					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 40.				
Commodity Charge per Therm:					
All Usage	$ .17367	($ .02996)	$ .35399	$ .49770	I
G-65– Biogas and Renewable Natural Gas Service					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 41A.				
Commodity Charge per Therm:					
All Usage	As specified on A.C.C. Sheet No. 41A.				

STATEMENT OF RATES

EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/

(Continued)

Description	Delivery Charge	3/ Rate Adjustment	Monthly Gas Cost	Currently Effective Tariff Rate	
G-75– Small Essential Agricultural User Gas Service					
Basic Service Charge per Month	$ 120.00			$ 120.00	
Commodity Charge per Therm:					
All Usage	$ .30638	($ .02996)	$ .35399	$ .63041	I
G-80 – Natural Gas Engine 6/ Water Pumping Gas Service					
Basic Service Charge per Month:					
Off-Peak Season (October–March)	$ .00			$ .00	
Peak Season (April–September)	$ 125.00			$ 125.00	
Commodity Charge per Therm:					
All Usage	$ .23275	$ .01972	$ .18273	$ .43520	I

1/ All charges are subject to adjustment for any applicable taxes or governmental impositions.

2/ Customers taking transportation service will pay the Basic Service Charge, the Commodity Charge per Therm less the Monthly Gas Cost, and Demand Charge, if applicable, of the Currently Effective Tariff Rate for each meter included in the transportation service agreement, plus an amount of $0.00283 per therm for distribution shrinkage as defined in Rule No. 1 of this Arizona Gas Tariff. The shrinkage charge shall be updated annually effective May 1. For customers converting from sales service, an additional amount equal to the currently effective Gas Cost Balancing Account Adjustment will be assessed for a period of 12 months.

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES [1/ 2/]
(Continued)

3/ The Rate Adjustment applicable to each tariff rate schedule includes the following components.

Description	G-5, G-6	G-10, G-11	G-15	G-20	Adjustment Date	
Low Income Ratepayer Assistance	$ 0.01544	n/a	n/a	$ 0.01544	1st Billing Cycle in May	
Demand Side Management	0.00745	$ 0.00200	$ 0.00745	0.00745	Per Commission Order	
Gas Infrastructure Recovery Charge	0.00952	0.00952	0.00952	0.00952	Per Commission Order	D/N
Department of Transportation	0.00275	0.00275	0.00275	0.00275	1st Billing Cycle in March	
Gas Cost Balancing Account	(0.04968)	(0.04968)	(0.04968)	(0.04968)	Per Commission Notification	D
DCA	0.00213	0.00213	n/a	n/a	Per Commission Order	
Total Rate Adjustment	$ (0.01239)	$ (0.03328)	$ (0.02996)	$ (0.01452)		I/D

Description	G-25S, G-25M, G-25-L1, G-25-L2	G-25TE, G-40, G-45, G-55, G-60, G-75	G-80	G-30, SB-1, Special Contracts	Adjustment Date	
Low Income Ratepayer Assistance	n/a	n/a	n/a	n/a	1st Billing Cycle in May	
Demand Side Management	$ 0.00745	$ 0.00745	$ 0.00745	n/a	Per Commission Order	
Gas Infrastructure Recovery Charge	0.00952	0.00952	0.00952	n/a	Per Commission Order	D/N
Department of Transportation	0.00275	0.00275	0.00275	$ 0.00275	1st Billing Cycle in March	
Gas Cost Balancing Account	(0.04968)	(0.04968)	n/a	n/a	Per Commission Notification	D
DCA	0.00213	n/a	n/a	n/a	Per Commission Order	
Total Rate Adjustment	$ ($0.02783)	$ (0.02996)	$ $0.01972	$ 0.00275		I/D

4/ The total monthly demand charge is equal to the unit rate shown multiplied by the customer's billing determinant.

5/ The charges for Schedule No. G-55 are subject to adjustment for applicable state and federal taxes on fuel used in motor vehicles.

6/ The gas cost for this rate schedule shall be updated seasonally, April 1 and October 1 of each year.

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

	____________	A.C.C. Sheet No.	14
Canceling	____________	A.C.C. Sheet No.	____________

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/
(Continued)

3/ The Rate Adjustment applicable to each tariff rate schedule includes the following components.

Description	G-5, G-6	G-10, G-11	G-15	G-20	Adjustment Date	
Low Income Ratepayer Assistance	$ 0.01544	n/a	n/a	$ 0.01544	1st Billing Cycle in May	
Demand Side Management	0.00745	$ 0.00200	$ 0.00745	0.00745	Per Commission Order	
~~VSP Replacement Program~~	~~0.00386~~	~~0.00386~~	~~0.00386~~	~~0.00386~~	~~Per Commission Order~~	D
Gas Infrastructure Recovery Charge	0.00952	0.00952	0.00952	0.00952	Per Commission Order	-N
Department of Transportation	0.00275	0.00275	0.00275	0.00275	1st Billing Cycle in March	
Gas Cost Balancing Account	(0.04968)	(0.04968)	(0.04968)	(0.04968)	Per Commission Notification	
~~COYL Cost Recovery~~	~~0.00566~~	~~0.00566~~	~~0.00566~~	~~0.00566~~	~~Per Commission Order~~	D
DCA	0.00213	0.00213	n/a	n/a	Per Commission Order	
~~Tax Reform Credit~~	~~(0.03170)~~	~~(0.03170)~~	~~(0.03170)~~	~~(0.03170)~~	~~Per Commission Order~~	D
Total Rate Adjustment	$ (0.01239)~~$ (0.04409)~~	$ (0.03328)~~$ (0.06498)~~	$ (0.02996)~~$ (0.06166)~~	$ (0.01452)~~$ (0.04622)~~		I

Description	G-25S, G-25M, G-25-L1, G-25-L2	G-25TE, G-40, G-45, G-55, G-60, G-75	G-80	G-30, SB-1, Special Contracts	Adjustment Date	
Low Income Ratepayer Assistance	n/a	n/a	n/a	n/a	1st Billing Cycle in May	
Demand Side Management	$ 0.00745	$ 0.00745	$ 0.00745	n/a	Per Commission Order	
~~VSP~~	~~0.00386~~	~~0.00386~~	~~0.00386~~	~~n/a~~	~~Per Commission Order~~	D
Gas Infrastructure Recovery Charge	0.00952	0.00952	0.00952	n/a	Per Commission Order	N
Department of Transportation	0.00275	0.00275	0.00275	$ 0.00275	1st Billing Cycle in March	
Gas Cost Balancing Account	(0.04968)	(0.04968)	n/a	n/a	Per Commission Notification	
~~COYL Cost Recovery~~	~~0.00566~~	~~0.00566~~	~~0.00566~~	~~n/a~~	~~Per Commission Order~~	D
DCA	0.00213	n/a	n/a	n/a	Per Commission Order	
~~Tax Reform Credit~~	~~(0.03170)~~	~~(0.03170)~~	~~(0.03170)~~	~~n/a~~	~~Per Commission Order~~	D
Total Rate Adjustment	$ ~~($0.05953)~~(0.02783)	$ ~~(0.06166)~~(0.02996)	$~~($0.01198)~~0.01972	$ 0.00275		I

4/ The total monthly demand charge is equal to the unit rate shown multiplied by the customer's billing determinant.

5/ The charges for Schedule No. G-55 are subject to adjustment for applicable state and federal taxes on fuel used in motor vehicles.

6/ The gas cost for this rate schedule shall be updated seasonally, April 1 and October 1 of each year.

Issued On ____________
Docket No. G-01551A-19-0055

Issued by
Justin Lee Brown
Senior Vice President

Effective ____________
Decision No. ____________

Schedule No. G-10

SINGLE-FAMILY LOW INCOME RESIDENTIAL GAS SERVICE
(Continued)

SPECIAL CONDITIONS *(Continued)*

2. Eligible customers shall be billed under this schedule with the next regularly scheduled billing period after the Utility has received the customer's properly completed application form or recertification.
3. Eligibility information provided by the customer on the application form may be subject to verification by the Utility. Refusal or failure of a customer to provide current documentation of eligibility acceptable to the Utility, upon request of the Utility, shall result in removal from or ineligibility for this schedule.
4. Customers who wrongfully declare eligibility or fail to notify the Utility when they no longer meet the eligibility requirements may be rebilled for the period of ineligibility under their otherwise applicable residential schedule.
5. It is the responsibility of the customer to notify the Utility within 30 days of any changes in the customer's eligibility status. D
6. All monetary discounts will be tracked through a balancing account established by the Utility and recovered through the Utility's Low Income Ratepayer Assistance (LIRA) Rate Adjustment Provision. T
7. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility. T

PURCHASED GAS ADJUSTMENT CLAUSE

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. G-10

SINGLE-FAMILY LOW INCOME RESIDENTIAL GAS SERVICE
(Continued)

SPECIAL CONDITIONS *(Continued)*

2. Eligible customers shall be billed under this schedule with the next regularly scheduled billing period after the Utility has received the customer's properly completed application form or recertification.

3. Eligibility information provided by the customer on the application form may be subject to verification by the Utility. Refusal or failure of a customer to provide current documentation of eligibility acceptable to the Utility, upon request of the Utility, shall result in removal from or ineligibility for this schedule.

4. Customers who wrongfully declare eligibility or fail to notify the Utility when they no longer meet the eligibility requirements may be rebilled for the period of ineligibility under their otherwise applicable residential schedule.

5. It is the responsibility of the customer to notify the Utility within 30 days of any changes in the customer's eligibility status.

~~6. Customers with connected service to pools, spas or hot tubs are eligible for this schedule, only if usage is prescribed, in writing, by a licensed physician.~~ D

~~7.~~6. All monetary discounts will be tracked through a balancing account established by the Utility and recovered through the Utility's Low Income Ratepayer Assistance (LIRA) Rate Adjustment Provision. T

~~8.~~7. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility. T

PURCHASED GAS ADJUSTMENT CLAUSE

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. G-11

MULTI-FAMILY LOW INCOME RESIDENTIAL GAS SERVICE
(Continued)

SPECIAL CONDITIONS *(Continued)*

2. Eligible customers shall be billed under this schedule with the next regularly scheduled billing period after the Utility has received the customer's properly completed application form or recertification.
3. Eligibility information provided by the customer on the application form may be subject to verification by the Utility. Refusal or failure of a customer to provide current documentation of eligibility acceptable to the Utility, upon request of the Utility, shall result in removal from or ineligibility for this schedule.
4. Customers who wrongfully declare eligibility or fail to notify the Utility when they no longer meet the eligibility requirements may be rebilled for the period of ineligibility under their otherwise applicable residential schedule.
5. It is the responsibility of the customer to notify the Utility within 30 days of any changes in the customer's eligibility status. D
6. All monetary discounts will be tracked through a balancing account established by the Utility and recovered through the Utility's Low Income Ratepayer Assistance (LIRA) Rate Adjustment Provision. T
7. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility. T

PURCHASED GAS ADJUSTMENT CLAUSE

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. G-11

MULTI-FAMILY LOW INCOME RESIDENTIAL GAS SERVICE
(Continued)

SPECIAL CONDITIONS *(Continued)*

2. Eligible customers shall be billed under this schedule with the next regularly scheduled billing period after the Utility has received the customer's properly completed application form or recertification.

3. Eligibility information provided by the customer on the application form may be subject to verification by the Utility. Refusal or failure of a customer to provide current documentation of eligibility acceptable to the Utility, upon request of the Utility, shall result in removal from or ineligibility for this schedule.

4. Customers who wrongfully declare eligibility or fail to notify the Utility when they no longer meet the eligibility requirements may be rebilled for the period of ineligibility under their otherwise applicable residential schedule.

5. It is the responsibility of the customer to notify the Utility within 30 days of any changes in the customer's eligibility status.

~~6. Customers with connected service to pools, spas or hot tubs are eligible for this schedule, only if usage is prescribed, in writing, by a licensed physician.~~ D

~~7.~~6. All monetary discounts will be tracked through a balancing account established by the Utility and recovered through the Utility's Low Income Ratepayer Assistance (LIRA) Rate Adjustment Provision. T

~~8.~~7. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility. T

PURCHASED GAS ADJUSTMENT CLAUSE

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. G-80

NATURAL GAS ENGINE WATER PUMPING GAS SERVICE

APPLICABILITY

Applicable to gas service to all customers using gas for fuel in internal combustion engines for pumping water for agricultural, domestic, and municipal purposes. T

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

1. All gas shall be supplied at a single point of delivery and measured through one meter. No other equipment may be supplied through this meter.
2. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

D

Schedule No. G-80

NATURAL GAS ENGINE WATER PUMPING GAS SERVICE

APPLICABILITY

Applicable to gas service to all customers using gas for fuel in internal combustion engines for pumping water for agricultural~~ irrigation purposes~~, domestic, and municipal~~, electric generation (excluding utility electric generation) or other mechanical~~ purposes. T T

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

1. All gas shall be supplied at a single point of delivery and measured through one meter. No other equipment may be supplied through this meter.
2. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

~~PURCHASED GAS ADJUSTMENT CLAUSE~~ D

~~The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.~~ D

SPECIAL SUPPLEMENTARY TARIFF
PURCHASED GAS COST ADJUSTMENT PROVISION

APPLICABILITY

This Purchased Gas Cost Adjustment Provision shall apply to all schedules except for Rate Schedule Nos. G-30, G-80, T-1, and SB-1 of this Arizona Gas Tariff. T

CHANGE IN RATES

The Monthly Gas Cost (MGC) rate for schedules covered by this provision includes the sum of the rolling twelve-month average purchased gas (PGA) rate plus the Gas Cost Balancing Account Adjustment, if applicable. Monthly adjustments will be made to the MGC to reflect the most currently available PGA rate. In accordance with Decision No. 70665, the PGA rate included in the MGC rate cannot be more than $.15 per therm different than any PGA rate in effect during the preceding 12 months.

BANK BALANCE

The Utility shall establish and maintain a Gas Cost Balancing Account, if necessary, for the schedules subject to this provision. Entries shall be made to this account each month, if appropriate, as follows:

1. A debit or credit entry equal to the difference between (a) the actual purchased gas cost for the month and (b) an amount determined by multiplying the Monthly Gas Cost Rate as set forth on Sheet Nos. 11 and 12 of this Arizona Gas Tariff by the therms billed during the month under the applicable schedules of this Arizona Gas Tariff.

2. A debit or credit entry for refunds or payments authorized by the Commission.

3. A debit or credit entry for interest to be applied to over- and under-collected bank balances based on the monthly one-year nominal Treasury constant maturities rate.

SPECIAL SUPPLEMENTARY TARIFF
PURCHASED GAS COST ADJUSTMENT PROVISION

APPLICABILITY

This Purchased Gas Cost Adjustment Provision shall apply to all schedules except for Rate Schedule Nos. G-30, G-80, T-1, and SB-1 of this Arizona Gas Tariff. T

CHANGE IN RATES

The Monthly Gas Cost (MGC) rate for schedules covered by this provision includes the sum of the rolling twelve-month average purchased gas (PGA) rate plus the Gas Cost Balancing Account Adjustment, if applicable. Monthly adjustments will be made to the MGC to reflect the most currently available PGA rate. In accordance with Decision No. 70665, the PGA rate included in the MGC rate cannot be more than $.15 per therm different than any PGA rate in effect during the preceding 12 months.

BANK BALANCE

The Utility shall establish and maintain a Gas Cost Balancing Account, if necessary, for the schedules subject to this provision. Entries shall be made to this account each month, if appropriate, as follows:

1. A debit or credit entry equal to the difference between (a) the actual purchased gas cost for the month and (b) an amount determined by multiplying the Monthly Gas Cost Rate as set forth on Sheet Nos. 11 and 12 of this Arizona Gas Tariff by the therms billed during the month under the applicable schedules of this Arizona Gas Tariff.

2. A debit or credit entry for refunds or payments authorized by the Commission.

3. A debit or credit entry for interest to be applied to over- and under-collected bank balances based on the monthly one-year nominal Treasury constant maturities rate.

SPECIAL SUPPLEMENTARY TARIFF N

RENEWABLE NATURAL GAS PROGRAM ENVIRONMENTAL ATTRIBUTE PROVISION

ENVIRONMENTAL ATTRIBUTES

The Utility's sale or other monetization of any Environmental Attributes associated with the Renewable Natural Gas Program (RNG Program) will be permitted pursuant to the terms of the RNG Program. All funds received by the Utility from the sale or other monetization of any Environmental Attributes associated with the RNG Program shall be credited to Account No. 191, Unrecovered Purchased Gas Costs. N

~~HELD FOR FUTURE USE~~ SPECIAL SUPPLEMENTARY TARIFF

RENEWABLE NATURAL GAS PROGRAM ENVIRONMENTAL ATTRIBUTE PROVISION

N

ENVIRONMENTAL ATTRIBUTES

The Utility's sale or other monetization of any Environmental Attributes associated with the Renewable Natural Gas Program (RNG Program) will be permitted pursuant to the terms of the RNG Program. All funds received by the Utility from the sale or other monetization of any Environmental Attributes associated with the RNG Program shall be credited to Account No. 191, Unrecovered Purchased Gas Costs.

N

SPECIAL SUPPLEMENTARY TARIFF
LOW INCOME RATEPAYER ASSISTANCE (LIRA) RATE ADJUSTMENT PROVISION T

APPLICABILITY

Applicable to all gas delivered by the Utility to all customers served under Rate Schedule Nos. G-5, G-6 and G-20.

RATES

The unit LIRA rate adjustment is set forth in the currently effective Statement of Rates, Footnote 3, of Sheet No. 14 of this Arizona Gas Tariff and is incorporated herein by reference.

CHANGES IN RATES

Rates applicable to each schedule of this Arizona Gas Tariff subject to this provision shall be adjusted for changes in the LIRA Balancing Account's balance in accordance with the rate adjustment provisions hereof such that the Utility will be reimbursed for all LIRA discounts, plus interest and administrative expenses.

ADJUSTMENT DATE

The LIRA rate adjustment shall be updated annually effective May 1.

RATE ADJUSTMENT PROVISIONS

Calculation of the LIRA rate adjustment shall include:

1. The LIRA program benefits provided during the prior Winter Season.
2. Incremental administrative and general expenses associated with the LIRA program.
3. The amounts accumulated in the LIRA Balancing Account as described below at the end of the latest available recorded month prior to the applicable Adjustment Date.
4. The sum of paragraphs (1), (2), and (3) above divided by the most recent 12 month's applicable sales volumes shall be the LIRA rate adjustment amount.

SPECIAL SUPPLEMENTARY TARIFF
LOW INCOME RATEPAYER ASSISTANCE (LIRA) RATE ADJUSTMENT PROVISION T

APPLICABILITY

Applicable to all gas delivered by the Utility to all customers served under Rate Schedule Nos. G-5, G-6 and G-20.

RATES

The unit LIRA rate adjustment is set forth in the currently effective Statement of Rates, Footnote 3, of Sheet No. 14 of this Arizona Gas Tariff and is incorporated herein by reference.

CHANGES IN RATES

Rates applicable to each schedule of this Arizona Gas Tariff subject to this provision shall be adjusted for changes in the LIRA Balancing Account's balance in accordance with the rate adjustment provisions hereof such that the Utility will be reimbursed for all LIRA discounts, plus interest and administrative expenses.

ADJUSTMENT DATE

The LIRA rate adjustment shall be updated annually effective May 1.

RATE ADJUSTMENT PROVISIONS

Calculation of the LIRA rate adjustment shall include:

1. The LIRA program benefits provided during the prior Winter Season.
2. Incremental administrative and general expenses associated with the LIRA program.
3. The amounts accumulated in the LIRA Balancing Account as described below at the end of the latest available recorded month prior to the applicable Adjustment Date.
4. The sum of paragraphs (1), (2), and (3) above divided by the most recent 12 month's applicable sales volumes shall be the LIRA rate adjustment amount.

SPECIAL SUPPLEMENTARY TARIFF
DELIVERY CHARGE ADJUSTMENT

APPLICABILITY

The Delivery Charge Adjustment (DCA) applies to residential Rate Schedule Nos. G-5, G-6, G-10 and G-11 and to General Service Schedule Nos. G-25(Small), G-25(Medium), G-25(Large-1) and G-25(Large-2) included in this Arizona Gas Tariff. The DCA specifies the accounting procedures and rate setting adjustments necessary to assure the Utility neither over-recovers, nor under-recovers, the margin-per-customer amounts authorized in its most recent general rate case proceeding.

CHANGE IN RATES

Annually, the DCA surcharge will adjust to recover or refund any differences between the Utility's billed margin and the margin amounts authorized in its most recent general rate case proceeding. The process is set forth below.

1) BALANCING ACCOUNT

The Utility shall maintain accounting records that accumulate the difference between authorized and actual billed margin. Entries shall be recorded to the DCA Balancing Account (DCABA) each month as follows:

A. A debit or credit entry equal to the difference between authorized margin and actual billed margin for each rate schedule subject to this provision. Authorized margin is the product of the monthly margin-per-customer authorized in the Utility's last general rate case, as stated below, and the actual number of customers billed during the month.

	G-5	G-6	G-10	G-11	
January	$ 59.82	$ 34.86	$ 57.36	$ 40.05	I
February	$ 52.31	$ 32.06	$ 51.01	$ 36.41	I
March	$ 42.52	$ 28.01	$ 40.19	$ 30.62	I
April	$ 31.33	$ 23.88	$ 29.56	$ 25.11	I
May	$ 25.07	$ 21.37	$ 23.39	$ 21.94	I
June	$ 24.27	$ 21.00	$ 22.62	$ 21.78	I
July	$ 22.39	$ 19.66	$ 20.95	$ 20.22	I
August	$ 21.43	$ 19.01	$ 20.08	$ 19.48	I
September	$ 21.94	$ 19.35	$ 20.40	$ 19.75	I
October	$ 22.96	$ 19.75	$ 21.20	$ 20.09	I
November	$ 25.29	$ 21.13	$ 24.01	$ 21.71	I
December	$ 44.07	$ 28.85	$ 42.59	$ 31.89	I

D

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7 ~~5th~~ 6th Revised A.C.C. Sheet No. 92
Arizona Division Canceling ~~4th~~ 5th Revised A.C.C. Sheet No. 92

SPECIAL SUPPLEMENTARY TARIFF
DELIVERY CHARGE ADJUSTMENT

APPLICABILITY

The Delivery Charge Adjustment (DCA) applies to residential Rate Schedule Nos. G-5, G-6, G-10 and G-11 and to General Service Schedule Nos. G-25(Small), G-25(Medium), G-25(Large-1) and G-25(Large-2) included in this Arizona Gas Tariff. The DCA specifies the accounting procedures and rate setting adjustments necessary to assure the Utility neither over-recovers, nor under-recovers, the margin-per-customer amounts authorized in its most recent general rate case proceeding.

CHANGE IN RATES

Annually, the DCA surcharge will adjust to recover or refund any differences between the Utility's billed margin and the margin amounts authorized in its most recent general rate case proceeding. The process is set forth below.

1) BALANCING ACCOUNT

The Utility shall maintain accounting records that accumulate the difference between authorized and actual billed margin. Entries shall be recorded to the DCA Balancing Account (DCABA) each month as follows:

A. A debit or credit entry equal to the difference between authorized margin and actual billed margin for each rate schedule subject to this provision. Authorized margin is the product of the monthly margin-per-customer authorized in the Utility's last general rate case, as stated below, and the actual number of customers billed during the month.

	G-5	G-6	G-10	G-11	
January	$ ~~56.27~~ 59.82	$ ~~31.70~~ 34.86	$ ~~54.75~~ 57.36	$ ~~37.15~~ 40.05	I
February	$ ~~48.76~~ 52.31	$ ~~28.90~~ 32.06	$ ~~48.40~~ 51.01	$ ~~33.51~~ 36.41	I
March	$ ~~38.97~~ 42.52	$ ~~24.85~~ 28.01	$ ~~37.58~~ 40.19	$ ~~27.72~~ 30.62	I
April	$ ~~27.78~~ 31.33	$ ~~20.72~~ 23.88	$ ~~26.95~~ 29.56	$ ~~22.21~~ 25.11	I
May	$ ~~21.52~~ 25.07	$ ~~18.20~~ 21.37	$ ~~20.78~~ 23.39	$ ~~19.04~~ 21.94	I
June	$ ~~20.72~~ 24.27	$ ~~17.83~~ 21.00	$ ~~20.00~~ 22.62	$ ~~18.88~~ 21.78	I
July	$ ~~18.83~~ 22.39	$ ~~16.49~~ 19.66	$ ~~18.33~~ 20.95	$ ~~17.31~~ 20.22	I
August	$ ~~17.87~~ 21.43	$ ~~15.84~~ 19.01	$ ~~17.46~~ 20.08	$ ~~16.57~~ 19.48	I
September	$ ~~18.38~~ 21.94	$ ~~16.18~~ 19.35	$ ~~17.79~~ 20.40	$ ~~16.84~~ 19.75	I
October	$ ~~19.41~~ 22.96	$ ~~16.58~~ 19.75	$ ~~18.59~~ 21.20	$ ~~17.19~~ 20.09	I
November	$ ~~21.74~~ 25.29	$ ~~17.96~~ 21.13	$ ~~21.40~~ 24.01	$ ~~18.81~~ 21.71	I
December	$ ~~40.52~~ 44.07	$ ~~25.69~~ 28.85	$ ~~39.98~~ 42.59	$ ~~28.99~~ 31.89	I
~~Total~~	~~$ 350.77~~	~~$ 250.94~~	~~$ 342.01~~	~~$ 274.22~~	D

Issued by
Issued On ______ Justin Lee Brown Effective ______
Docket No. G-01551A-19-0055 Senior Vice President Decision No. ______ T

SPECIAL SUPPLEMENTARY TARIFF
DELIVERY CHARGE ADJUSTMENT
(Continued)

	G-25(S)	G-25(M)	G-25(L1)	G-25(L2)	
January	$ 76.28	$ 244.57	$ 939.99	$ 3,804.36	I
February	$ 68.08	$ 229.14	$ 876.86	$ 3,557.24	I
March	$ 57.90	$ 198.71	$ 764.23	$ 3,487.57	I
April	$ 45.03	$ 169.70	$ 680.24	$ 3,020.26	I
May	$ 40.50	$ 149.51	$ 590.81	$ 2,670.55	I
June	$ 40.20	$ 144.59	$ 552.87	$ 2,515.92	I
July	$ 38.62	$ 131.49	$ 477.48	$ 2,089.24	I
August	$ 37.99	$ 127.90	$ 454.29	$ 2,000.23	I
September	$ 38.29	$ 132.53	$ 472.04	$ 2,079.33	I
October	$ 38.78	$ 139.45	$ 514.31	$ 2,257.53	I
November	$ 40.77	$ 153.39	$ 593.95	$ 2,714.62	I
December	$ 57.73	$ 206.62	$ 809.83	$ 3,400.78	I

D

B. A debit or credit entry equal to the therms billed during the month under the schedules subject to this provision multiplied by the DCA surcharge rate.

C. A debit or credit entry for interest to be applied to over- and under-collected bank balances based on the monthly one-year nominal Treasury constant maturities rate.

2) RATE ADJUSTMENT
The DCA Rate Adjustment applicable to each schedule subject to this provision shall be revised annually to reflect the difference between the margin-per-customer authorized in the Utility’s last general rate case and the margin billed. The DCA Rate Adjustment will be calculated by dividing the balance in the DCABA by the most recent 12-month volume of natural gas for the applicable rate schedules.

3) AMOUNTS RECOVERED AND REFUNDED
Over-collected or under-collected balances in the DCABA will be refunded over the next amortization period.

4) TIMING AND MANNER OF FILING
The Utility shall file its DCA Rate Adjustment revisions with the Commission in accordance with all statutory and regulatory requirements. The DCA Rate Adjustment shall be effective on the date of the first bill cycle in the month following the Commission’s approval unless otherwise provided for by the Commission.

SPECIAL SUPPLEMENTARY TARIFF
DELIVERY CHARGE ADJUSTMENT
(Continued)

	G-25(S)	G-25(M)	G-25(L1)	G-25(L2)	
January	$ ~~72.34~~ 76.28	$~~221.00~~ 244.57	$~~896.24~~ 939.99	$~~3,550.90~~ 3,804.36	I
February	$ ~~64.14~~ 68.08	$~~205.57~~ 229.14	$~~833.11~~ 876.86	$~~3,303.78~~ 3,557.24	I
March	$ ~~53.95~~ 57.90	$~~175.14~~ 198.71	$~~720.48~~ 764.23	$~~3,234.11~~ 3,487.57	I
April	$ ~~41.08~~ 45.03	$~~146.13~~ 169.70	$~~636.49~~ 680.24	$~~2,766.80~~ 3,020.26	I
May	$ ~~36.55~~ 40.50	$~~125.94~~ 149.51	$~~547.06~~ 590.81	$~~2,417.09~~ 2,670.55	I
June	$ ~~36.25~~ 40.20	$~~121.02~~ 144.59	$~~509.11~~ 552.87	$~~2,262.46~~ 2,515.92	I
July	$ ~~34.67~~ 38.62	$~~107.92~~ 131.49	$~~433.72~~ 477.48	$~~1,835.78~~ 2,089.24	I
August	$ ~~34.04~~ 37.99	$~~104.32~~ 127.90	$~~410.53~~ 454.29	$~~1,746.76~~ 2,000.23	I
September	$ ~~34.34~~ 38.29	$~~108.96~~ 132.53	$~~428.28~~ 472.04	$~~1,825.86~~ 2,079.33	I
October	$ ~~34.83~~ 38.78	$~~115.88~~ 139.45	$~~470.55~~ 514.31	$~~2,004.07~~ 2,257.53	I
November	$ ~~36.82~~ 40.77	$~~129.82~~ 153.39	$~~550.20~~ 593.95	$~~2,461.16~~ 2,714.62	I
December	$ ~~53.78~~ 57.73	$~~183.05~~ 206.62	$~~766.08~~ 809.83	$~~3,147.32~~ 3,400.78	I
~~Total~~	~~$ 532.79~~	~~$ 1,744.75~~	~~$ 7,201.85~~	~~$ 30,556.09~~	D

B. A debit or credit entry equal to the therms billed during the month under the schedules subject to this provision multiplied by the DCA surcharge rate.

C. A debit or credit entry for interest to be applied to over- and under-collected bank balances based on the monthly one-year nominal Treasury constant maturities rate.

2) RATE ADJUSTMENT

The DCA Rate Adjustment applicable to each schedule subject to this provision shall be revised annually to reflect the difference between the margin-per-customer authorized in the Utility's last general rate case and the margin billed. The DCA Rate Adjustment will be calculated by dividing the balance in the DCABA by the most recent 12-month volume of natural gas for the applicable rate schedules.

3) AMOUNTS RECOVERED AND REFUNDED

Over-collected or under-collected balances in the DCABA will be refunded over the next amortization period.

4) TIMING AND MANNER OF FILING

The Utility shall file its DCA Rate Adjustment revisions with the Commission in accordance with all statutory and regulatory requirements. The DCA Rate Adjustment shall be effective on the date of the first bill cycle in the month following the Commission's approval unless otherwise provided for by the Commission.

RULE NO. 1

DEFINITIONS

For the purpose of these Tariffs, the terms and expressions listed below shall have the meanings set forth opposite:

Advance in Aid of Construction:	Funds provided to the Utility by an applicant for service under the terms of a main extension agreement, the amount of which may be refundable.
Agent:	Any party a customer may contract with for purposes of administering the customer's service agreement with the Utility excluding the right for the Agent to be billed directly by the Utility. An Agent has only those rights designated in writing by such customer for the effective time period.
Alternate Fuel:	Any fuel, gaseous, liquid, or solid, that may be used in lieu of natural gas. N N
Alternate Fuel Capability:	A situation where an alternate fuel can be utilized whether or not the facilities for such use have actually been installed.
Applicant:	A person requesting the Utility to supply natural gas service.
Application:	A request to the Utility for natural gas service, as distinguished from an inquiry as to the availability or charges for such service.
Arizona Corporation Commission:	The regulatory authority of the State of Arizona having jurisdiction over the public service corporations operating in Arizona.
Average Month:	30.4 days.
Base Gas Supply:	Natural gas purchased by the Utility from its primary supplier.
Basic Service Charge:	A fixed amount a customer must pay the Utility for the availability of gas service, independent of consumption, as specified in the Utility's tariffs.
Billing Month:	The period between any two regular readings of the Utility's meters at intervals of approximately 30 days.

D/L

RULE NO. 1

DEFINITIONS

For the purpose of these Tariffs, the terms and expressions listed below shall have the meanings set forth opposite:

Advance in Aid of Construction:	Funds provided to the Utility by an applicant for service under the terms of a main extension agreement, the amount of which may be refundable.	
Agent:	Any party a customer may contract with for purposes of administering the customer's service agreement with the Utility excluding the right for the Agent to be billed directly by the Utility. An Agent has only those rights designated in writing by such customer for the effective time period.	
Alternate Fuel:	Any fuel, gaseous, liquid, or solid, that may be used in lieu of natural gas.	N N
Alternate Fuel Capability:	A situation where an alternate fuel can be utilized whether or not the facilities for such use have actually been installed.	
Applicant:	A person requesting the Utility to supply natural gas service.	
Application:	A request to the Utility for natural gas service, as distinguished from an inquiry as to the availability or charges for such service.	
Arizona Corporation Commission:	The regulatory authority of the State of Arizona having jurisdiction over the public service corporations operating in Arizona.	
Average Month:	30.4 days.	
Base Gas Supply:	Natural gas purchased by the Utility from its primary supplier.	
Basic Service Charge:	A fixed amount a customer must pay the Utility for the availability of gas service, independent of consumption, as specified in the Utility's tariffs.	
Billing Month:	The period between any two regular readings of the Utility's meters at intervals of approximately 30 days.	
~~Billing Period:~~	~~The time interval between two consecutive meter readings that are taken for billing purposes.~~	D/L

RULE NO. 1

DEFINITIONS
(Continued)

Billing Period:	The time interval between two consecutive meter readings that are taken for billing purposes.	L L
Billing Units:	The billing unit shall be in either therms or hundreds of cubic feet (Ccf), whichever is applicable.	
Biogas:	A mixture of methane, carbon dioxide, and other constituents that is produced by the anaerobic digestion with anaerobic bacteria or fermentation of biodegradable materials such as biomass (manure, sewage, green waste, plant material, crops, and municipal waste or landfills).	N N
Branch Service:	A service that is not connected to a natural gas main and has as its source of supply another service.	
British Thermal Unit:	The amount of heat required to raise the temperature of one pound of water from 59ºF. to 60ºF at constant pressure of 14.73 pounds per square inch absolute (psia).	
Btu:	British thermal unit.	
Bypass:	The ability to supplement or replace the Utility's natural gas service with another energy source not provided or delivered by the Utility.	N N
Bypass Customer:	A customer who has the ability, because of its physical proximity to the facilities of an alternative pipeline, or who possesses the ability to bypass the Utility's system and secure natural gas service from that pipeline or from another energy source not provided by the Utility.	T T

D/L

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RULE NO. 1

DEFINITIONS
(Continued)

Billing Period:	The time interval between two consecutive meter readings that are taken for billing purposes.
Billing Units:	The billing unit shall be in either therms or hundreds of cubic feet (Ccf), whichever is applicable.
Biogas:	A mixture of methane, carbon dioxide, and other constituents that is produced by the anaerobic digestion with anaerobic bacteria or fermentation of biodegradable materials such as biomass (manure, sewage, green waste, plant material, crops, and municipal waste or landfills).
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British Thermal Unit:	The amount of heat required to raise the temperature of one pound of water from 59ºF. to 60ºF at constant pressure of 14.73 pounds per square inch absolute (psia).
Btu:	British thermal unit.
Bypass:	The ability to supplement or replace the Utility's natural gas service with another energy source not provided or delivered by the Utility.
Bypass Customer:	A ~~transportation~~ customer who has the ability, because of its physical proximity to the facilities of an alternative pipeline, or who possesses the ability to bypass the Utility's system and secure natural gas service from that pipeline or from another energy source not provided by the Utility.
~~Capacity Curtailment:~~	~~A condition occurring when the total system demand for natural gas exceeds the system's capability to deliver gas.~~

~~Cogeneration:~~ ~~The use of gas to generate electricity and thermal energy at a facility that meets the efficiency standards outlined in Title 18, Code of Federal Regulation, Part 292, Subparts A and B, and where the customer's generators and load are located at the same site.~~

~~Commercial Customer:~~ ~~A customer who is engaged primarily in the sale of goods or services including institutions and local, state and federal government agencies for uses other than those involving manufacturing or electric power generation.~~ D/L

RULE NO. 1

DEFINITIONS
(Continued)

Capacity Curtailment:	A condition occurring when the total system demand for natural gas exceeds the system's capability to deliver gas.
Cogeneration:	The use of gas to generate electricity and thermal energy at a facility that meets the efficiency standards outlined in Title 18, Code of Federal Regulation, Part 292, Subparts A and B, and where the customer's generators and load are located at the same site.
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RULE NO. 1

DEFINITIONS
(Continued)

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RULE NO. 1

DEFINITIONS
(Continued)

Cubic Foot: *(Continued)*	3.	For the testing of gas for heating value the standard cubic foot shall be that volume of gas which, when saturated with water vapor and at a temperature of 60°F and under a pressure equivalent to that of 30 inches of mercury (mercury at 32°F and under standard gravity), occupies 1 cubic foot.
Ccf:		One hundred (100) cubic feet.
Curtailment Priority:		The order in which natural gas service is to be curtailed to various classifications of customers, as set forth in Rule No. 7 on A.C.C. Sheet Nos. 216 - 218 of this Arizona Gas Tariff.
Customer:		The person in whose name service is rendered as evidenced by the signature on the application, contract, or agreement for that service, or in the absence of a signed instrument, by the receipt and payment of bills regularly issued in his name, regardless of the identity of the actual user of the service.
Customer Piping System:		All pipe, tubing, valves, fittings, regulators, meters, or other components from the point of delivery to the outlets of the appliance shutoff valves. The term excludes appliance connectors and appliances. D/N – N

RULE NO. 1

DEFINITIONS
(Continued)

Cubic Foot: *(Continued)*	3.	For the testing of gas for heating value the standard cubic foot shall be that volume of gas which, when saturated with water vapor and at a temperature of 60°F and under a pressure equivalent to that of 30 inches of mercury (mercury at 32°F and under standard gravity), occupies 1 cubic foot.
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Customer:		The person in whose name service is rendered as evidenced by the signature on the application, contract, or agreement for that service, or in the absence of a signed instrument, by the receipt and payment of bills regularly issued in his name, regardless of the identity of the actual user of the service.
Customer Piping System:	~~1.~~	~~House piping - All above-ground piping downstream of the point of delivery; and~~ D
~~2.~~		~~Yard piping - All below-ground piping downstream of the point of delivery.~~
		~~Both of which are the responsibility of the customer. Customer piping does not include meters and any associated regulators, pipe, fixtures, apparatus, etc., owned and operated by the Utility.~~ D
		All pipe, tubing, valves, fittings, regulators, meters, or other components from the point of delivery to the outlets of the appliance shutoff valves. The term excludes appliance connectors and appliances. N

RULE NO. 1

DEFINITIONS
(Continued)

Inter-Divisional Capacity Transfer:	A mechanism by which the unused off-peak interstate capacity of one of the Utility's divisions is utilized by another of the Utility's divisions to procure and transport otherwise inaccessible economically priced gas. The division owning the off-peak capacity receives benefit in the form of credits to its Gas Cost Balancing Account. The division utilizing the off-peak capacity receives benefit through reduction in its purchased gas costs.
Input Rating:	The number of Btus specified on the appliance rating tag needed to operate the appliance. Normally expressed in Btus per hour.
Irrigation Customer:	Where natural gas is utilized by internal combustion engines for agricultural irrigation purposes.
Law:	A rule or rules as established and enforced by government authorities.
Leak Check:	A pressure test of the customer piping system using natural gas at standard delivery pressure as the test medium, or, in the judgment of the utility, at a higher pressure. L/T L
Main Extension	The addition of pipe to an existing main to provide service to new customers.
Margin:	The currently effective commodity delivery charges multiplied by the units of gas used, plus the Demand Delivery charges multiplied by the billing determinant, if applicable, plus the basic service charge is the margin.
Master Meter Customer:	A customer who receives gas at a central point and distributes said gas through a piping system not owned and operated by the Utility to tenants or occupants for their individual consumption.
Mcf:	One thousand (1,000) cubic feet.

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RULE NO. 1

DEFINITIONS
(Continued)

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Mcf:	One thousand (1,000) cubic feet.
~~Leak Check:~~	~~A pressure test of the customer's piping using natural gas at standard delivery pressure as the test medium, or, in the judgment of the utility, at a higher pressure.~~ D/L D/L D/L

RULE NO. 1

DEFINITIONS
(Continued)

Police Protection Uses:	Natural gas used by law enforcement agencies in the performance of their appointed duties.
Preemption of Gas Supply:	An emergency condition where the Utility may, under specified conditions, utilize the customer-owned gas supplies of low priority transportation customers to serve the requirements of higher priority transportation and sales customers.
Premises:	All real property and apparatus employed in a single-owner enterprise located on an integral parcel of land or on contiguous properties that are located immediately across a public right-of-way.
Process Gas:	Natural gas use for which alternate fuels are not technically feasible, such as in applications requiring precise temperature controls and precise flame characteristics. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels.
Regular Working Hours:	Except for Utility observed holidays, the period from 8 a.m. to 5 p.m., Monday through Friday.
Renewable Natural Gas (RNG):	A biogas which has been upgraded to pipeline quality gas that is suitable for distribution via the existing natural gas pipeline system, by increasing the percentage of methane in biogas by removing carbon dioxide and other trace components and adding a warning odorant. N
Residential Dwelling:	A house, apartment, townhouse, or any other permanent residential unit.
Residential Subdivision:	Any tract of land which has been divided into four or more contiguous lots for use for the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.
Residential Use:	Service to customers using natural gas for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, and other residential uses and includes use in apartment buildings, mobile home parks, and other multi-unit residential buildings.

RULE NO. 1

DEFINITIONS
(Continued)

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RULE NO. 1

DEFINITIONS
(Continued)

Service Establishment Charge:	A charge as specified in the Utility's tariffs for establishing a new account.
Service Line:	A natural gas pipe that transports gas from a common source of supply (normally a distribution main) to the point of delivery.
Service Line Extension:	Consists of a service line provided for a new customer at a premise not heretofore served, in accordance with the service line extension rule.
Service Line Shut-Off Valve:	A curb valve or other manually operated valve located near the service that is safely accessible to Company personnel or other personnel authorized by the Company to manually shut off gas flow to the service. N
Service Reconnect Charge:	A charge as specified in the Utility's tariffs which must be paid by the customer prior to reconnection of natural gas service each time the service is disconnected for nonpayment or whenever service is discontinued for failure to comply with the Utility's tariffs.
Service Reestablishment Charge:	A charge as specified in the Utility's tariffs for service at the same location where the same customer had ordered a service disconnection within the preceding 12-month period.
Shrinkage:	The cost of the gas volumes lost, unaccounted for, or used as company fuel in the transportation process and represented by the differential between the cost of gas on a sales basis and the cost of gas on a purchased basis.
Shrinkage Rate:	The rate used to recover the cost of shrinkage from non-exempt transportation customers.
Single-Family Residential:	A permanent residential dwelling, excluding multi-family residential structures.
Southwest Vista:	A fully integrated website that allows for the Utility's Transportation customers and designated agents the ability to submit Transportation nominations to the interstate pipelines. Users may also have the ability to view monthly volume statements, master detail reports, Transportation pipeline charges allocated to them from the Utility, and informational reports.

RULE NO. 1

DEFINITIONS
(Continued)

Service Establishment Charge:	A charge as specified in the Utility's tariffs for establishing a new account.
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Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

B. ESTABLISHMENT AND REESTABLISHMENT OF CREDIT/DEPOSITS *(Continued)*

3. Deposits *(Continued)*

e. Interest on Deposits
The Utility will pay interest on cash deposits held by the Company twelve (12) months or longer. The interest rate shall be the established one-year U.S. Treasury Constant Maturities rate, effective on the first business day of the year, as published on the Federal Reserve Website. C

f. The Utility may review the customer's usage after service has been connected and adjust the deposit amount based upon the customer's actual usage.

g. A separate deposit may be required for each meter installed.

h. The Utility shall issue a non-negotiable receipt to the applicant for the deposit. The inability of the customer to produce such a receipt shall in no way impair his right to receive a refund of the deposit which is reflected on the Utility's records.

C. GROUNDS FOR REFUSAL OF SERVICE

1. The Utility has the right, but not the responsibility, to refuse to establish service if any of the following conditions exists: T

a. The applicant has an outstanding amount due for the same class of service with the Utility and the applicant is unwilling to make satisfactory arrangements with the Utility for payment.

b. A condition exists which in the Utility's judgment is unsafe or hazardous to the applicant, the customer, the general population, or the Utility's personnel or facilities. T

c. Refusal by the applicant to provide the Utility with a deposit when the customer has failed to meet the credit criteria for waiver of deposit requirements.#

Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

B. ESTABLISHMENT AND REESTABLISHMENT OF CREDIT/DEPOSITS *(Continued)*

3. Deposits *(Continued)*

e. Interest on Deposits
The Utility will pay ~~6 percent~~ interest on cash deposits held by the Company twelve (12) months or longer ~~from the date of deposit until the date of settlement or withdrawal of deposit. Where such deposit remains for a period of one year or more and the person making the deposit continues to be a customer, the interest on the deposit at the end of the year shall be applied to the customer's account~~. The interest rate shall be the established one-year U.S. Treasury Constant Maturities rate, effective on the first business day of the year, as published on the Federal Reserve Website. C

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Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

C. GROUNDS FOR REFUSAL OF SERVICE *(Continued)*

d. Customer is known to be in violation of the Utility's tariffs filed with and approved by the Commission.

e. Failure of the customer to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the customer and which have been specified by the Utility as a condition for providing service.

f. Applicant falsifies his or her identity for the purpose of obtaining service.

g. Where service has been discontinued for fraudulent use, in which case Rule No. 11 will apply.

h. If the intended use of the service is for any restricted apparatus or prohibited use.

i. Failure of the applicant to provide an easement in a form and upon terms that are satisfactory to the Utility when such is requested by the Utility as provided in Rule No. 8D. N N N

2. Notification to Applicants or Customers

When an applicant or customer is refused service or service has been discontinued under the provisions of this rule, the Utility will notify the applicant or customer of the reasons for the refusal to serve and of the right of applicant or customer to appeal the Utility's decision to the Commission.

D. SERVICE ESTABLISHMENT, REESTABLISHMENT OR RECONNECTION

1. To recover the operating and clerical costs, the Utility shall collect a service charge whenever service is established, reestablished or reconnected as set forth and referred to as "Service Establishment Charge" in the currently effective Statement of Rates, A.C.C. Sheet No. 15 of this Arizona Gas Tariff. This charge will be applicable for (1) establishing a new account, (2) reestablishing service at the same location where the same customer had ordered a service disconnection, or (3) reconnecting service after having been discontinued for nonpayment of bills or for failure to otherwise comply with filed rules or tariff schedules.

Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

C. GROUNDS FOR REFUSAL OF SERVICE *(Continued)*

d. Customer is known to be in violation of the Utility's tariffs filed with and approved by the Commission.

e. Failure of the customer to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the customer and which have been specified by the Utility as a condition for providing service.

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RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

B. SERVICE AND MAIN EXTENSIONS TO APPLICANTS FOR SERVICE *(Continued)*

a. Allowable investment shall mean a determination by the Utility that the revenues less the incremental cost to serve the applicant customer provides a rate of return on the Utility's investment no less than the overall rate of return authorized by the Commission in the Utility's most recent general rate case.

b. The Utility, after conducting an Incremental Contribution study may, at its option, extend its facilities to Customers whose usage does not satisfy the definition of Economic Feasibility but who otherwise are Permanent Customers provided such Customer signs an extension agreement and advances as much of the cost, and/or agrees to pay a nonrefundable Facility Charge necessary to make the extension economically feasible.

c. Customers provided with line extensions using the Incremental Contribution Method shall be reviewed annually to determine the amount of any refund for a period of ten years.

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5. Method of Refund

Amounts advanced by the applicant in accordance with this rule, less any unpaid Facility Charges, shall be refunded, without interest, in the following manner:

a. Refunds of an advance shall be made for each additional separately metered permanent connections to the main extension for which an advance was collected when an excess allowable investment is calculated by the Incremental Contribution Study for the additional customer(s). T

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RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

B. SERVICE AND MAIN EXTENSIONS TO APPLICANTS FOR SERVICE *(Continued)*

a. Allowable investment shall mean a determination by the Utility that the revenues less the incremental cost to serve the applicant customer provides a rate of return on the Utility's investment no less than the overall rate of return authorized by the Commission in the Utility's most recent general rate case.

b. The Utility, after conducting an Incremental Contribution study may, at its option, extend its facilities to Customers whose usage does not satisfy the definition of Economic Feasibility but who otherwise are Permanent Customers provided such Customer signs an extension agreement and advances as much of the cost, and/or agrees to pay a nonrefundable Facility Charge necessary to make the extension economically feasible.

c. Customers provided with line extensions using the Incremental Contribution Method shall be reviewed annually to determine the amount of any refund~~ as follows:~~ for a period of ten years. C

~~(1) For a period of five years except as in Item (2) below.~~ D

~~(2) For a period of ten years for feeder mains to serve master-planned subdivisions.~~ D

5. Method of Refund

Amounts advanced by the applicant in accordance with this rule, less any unpaid Facility Charges, shall be refunded, without interest, in the following manner:

a. Refunds of an advance shall be made for each additional separately metered permanent ~~service connected~~ connections to the main extension for which an advance was collected when an excess allowable investment is calculated by the Incremental Contribution Study for the additional customer(s). T

~~b. No refunds will be made for additional customers connecting to a further extension or series of extensions constructed beyond the original extension.~~ D

RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

B. SERVICE AND MAIN EXTENSIONS TO APPLICANTS FOR SERVICE *(Continued)*

b. Refunds will be made annually, or intermittently within the annual period at the option of the Utility. Amounts refunded may be accumulated to a minimum of $50, or the total refundable balance if less than $50. T

c. When two or more parties make a joint advance on the same extension, refundable amounts will be distributed to these parties in the same proportion as their individual percentages of the total joint advance. T

d. The refund period shall be ten years from the date of the completion of the extension. No refunds will be made by the Utility after the termination of the refund period. Any portion of the advance that remains unrefunded at the end of the refund period shall remain the property of the Utility. C D D

e. Any assignment by a customer of their interest in any part of an advance, which at the time remains unrefunded, must be made in writing and approved by the Utility. T

f. Amounts advanced under a gas main extension rule previously in effect will be refunded in accordance with the provisions of such rule. T

C. SERVICE AND MAIN EXTENSIONS TO SERVE INDIVIDUALLY-METERED SUBDIVISIONS, TRACTS, HOUSING PROJECTS, MULTI-FAMILY DWELLINGS AND MOBILE HOME PARKS OR ESTATES

1. Advances

a. Gas distribution service and main extensions to and within individually-metered subdivisions, housing projects, multi-family dwellings and mobile home parks or estates will be constructed, owned and maintained by the Utility in advance of applications for service by bona fide customers only when the entire estimated cost of such extensions as determined by the Utility is advanced to the Utility, and a main extension contract is executed. This advance may include the cost of any gas facilities installed at the Utility's expense in conjunction with a previous service or main extension in anticipation of the current extension.

RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

B. SERVICE AND MAIN EXTENSIONS TO APPLICANTS FOR SERVICE *(Continued)*

~~c~~b. Refunds will be made annually, or intermittently within the annual period at the option of the Utility. Amounts refunded may be accumulated to a minimum of $50, or the total refundable balance if less than $50. T

~~d~~c. When two or more parties make a joint advance on the same extension, refundable amounts will be distributed to these parties in the same proportion as their individual percentages of the total joint advance. T

~~e~~d. The refund period shall be ~~five~~ ten years from the date of the completion of the extension., ~~except that in the case of feeder mains to serve master-planned subdivisions, the refund period shall be ten years.~~ No refunds will be made by the Utility after the termination of the refund period. Any portion of the advance that remains unrefunded at the end of the refund period shall remain the property of the Utility. C D D

~~f~~e. Any assignment by a customer of their interest in any part of an advance, which at the time remains unrefunded, must be made in writing and approved by the Utility. T

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C. SERVICE AND MAIN EXTENSIONS TO SERVE INDIVIDUALLY-METERED SUBDIVISIONS, TRACTS, HOUSING PROJECTS, MULTI-FAMILY DWELLINGS AND MOBILE HOME PARKS OR ESTATES

1. Advances

a. Gas distribution service and main extensions to and within individually-metered subdivisions, housing projects, multi-family dwellings and mobile home parks or estates will be constructed, owned and maintained by the Utility in advance of applications for service by bona fide customers only when the entire estimated cost of such extensions as determined by the Utility is advanced to the Utility, and a main extension contract is executed. This advance may include the cost of any gas facilities installed at the Utility's expense in conjunction with a previous service or main extension in anticipation of the current extension.

RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

D. RESIDENTIAL AMORTIZATION PROGRAM *(Continued)*

In instances where a customer that is a party to a line extension contract disconnects service, the entirety of the remaining balance of the principal of the contract shall become due and payable immediately by the customer to the Utility, unless such customer arranges for the subsequent customer requesting gas service at the same service address to execute a new line extension contract. This new contract shall obligate the subsequent customer to pay the monthly amortization charge under terms identical to those of the original contract.

In instances where the remaining balance of the principal becomes due and payable immediately, the Utility shall make reasonable efforts to collect such remaining balance from the customer; however, if such efforts prove unsuccessful, the defaulted balance shall become the Utility's investment in gross plant.

The residential amortization program shall not be available to developers, contractors or other commercial entities.

E. GENERAL CONDITIONS

1. Postponement of Advance

The Utility, at its option, may postpone, for a period not to exceed ten years, that portion of an advance which it estimates would be refunded under the provisions of this rule. At the end of such refund period, the Utility shall collect all such amounts not previously advanced which were not then refundable. When advances are postponed, the applicant may be required to furnish to the Utility evidence of the necessary approvals to commence construction and of adequate financing. A surety bond, or other Utility-approved surety, may be required to assure payment of any postponed amounts at the end of the postponement period. C

RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

D. RESIDENTIAL AMORTIZATION PROGRAM *(Continued)*

In instances where a customer that is a party to a line extension contract disconnects service, the entirety of the remaining balance of the principal of the contract shall become due and payable immediately by the customer to the Utility, unless such customer arranges for the subsequent customer requesting gas service at the same service address to execute a new line extension contract. This new contract shall obligate the subsequent customer to pay the monthly amortization charge under terms identical to those of the original contract.

In instances where the remaining balance of the principal becomes due and payable immediately, the Utility shall make reasonable efforts to collect such remaining balance from the customer; however, if such efforts prove unsuccessful, the defaulted balance shall become the Utility's investment in gross plant.

The residential amortization program shall not be available to developers, contractors or other commercial entities.

E. GENERAL CONDITIONS

1. Postponement of Advance

The Utility, at its option, may postpone, for a period not to exceed ~~five~~ ten years, that portion of an advance which it estimates would be refunded under the provisions of this rule. At the end of such refund period, the Utility shall collect all such amounts not previously advanced which were not then refundable. When advances are postponed, the applicant may be required to furnish to the Utility evidence of the necessary approvals to commence construction and of adequate financing. A surety bond, or other Utility-approved surety, may be required to assure payment of any postponed amounts at the end of the postponement period. C

RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

E. GENERAL CONDITIONS *(Continued)*

(3) Description and sketch of the requested main extension.

(4) Description of requested service.

(5) A cost estimate to include materials, labor, and other costs as necessary.

(6) Payment terms.

(7) A concise explanation of any refunding provisions, if applicable.

(8) The Utility's estimated start date and completion date for construction of the main extension.

(9) A summary of the results of the Incremental Contribution analysis performed by the Utility to determine the amount of advance required from the applicant for the proposed main extensions.

(10) Each applicant shall be provided a copy of the approved main extension agreement.

6. Relocation or Improvement of Services and Mains T

a. When, in the judgment of the Utility, the relocation or improvement of a main or service is necessary and is due either to maintenance of adequate service or the operating convenience of the Utility, the Utility shall perform such work at its own expense. T

b. If relocation or improvement of a main or service line is due solely to meet the convenience or the requirements of the applicant or the customer, such relocation or improvement, including metering and regulating facilities, shall be performed by the Utility at the expense of the applicant or the customer. T T

RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

E. GENERAL CONDITIONS *(Continued)*

(3) Description and sketch of the requested main extension.

(4) Description of requested service.

(5) A cost estimate to include materials, labor, and other costs as necessary.

(6) Payment terms.

(7) A concise explanation of any refunding provisions, if applicable.

(8) The Utility's estimated start date and completion date for construction of the main extension.

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(10) Each applicant shall be provided a copy of the approved main extension agreement.

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b. If relocation or improvement of a main or service line is due solely to meet the convenience or the requirements of the applicant or the customer, such relocation or improvement, including metering and regulating facilities, shall be performed by the Utility at the expense of the applicant or the customer. T T

RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

E. GENERAL CONDITIONS *(Continued)*

c. Relocation or improvement of facilities will be mandatory and at the customer's expense when actions of the customer restrict the Utility's access to or the safety of the facility. T

7. Standby Service or Residential Pool Heating

No allowance will be made for equipment used for standby or emergency purposes only. No allowance will be made for pool heaters for residential customers.

8. Temporary Service

Extensions for temporary service or for operations, which in the opinion of the Utility are of a speculative character or of questionable permanency will not be made under this rule, but will be made in accordance with Rule No. 3.

9. Length and Location

The length of main or service required for an extension will be considered as the distance along the shortest practical and available route, as determined by the Utility, from the Utility's nearest permanent distribution main.

10. Service Impairment to Other Customers

When, in the judgment of the Utility, providing service to an applicant would impair service to other customers, the cost of necessary reinforcement to eliminate such impairment may be included in the cost calculation for the extension.

11. Service From Transmission Lines

The Utility will not tap a gas transmission main except when conditions in its sole opinion justify such a tap. Where such taps are made, the applicant will pay the Utility the cost of such tap, and extensions therefrom will be made in accordance with the provisions of this rule.

RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

E. GENERAL CONDITIONS *(Continued)*

c. Relocation or improvement of facilities will be mandatory and at the customer's expense when actions of the customer restrict the Utility's access to or the safety of the facility. T

7. Standby Service or Residential Pool Heating

No allowance will be made for equipment used for standby or emergency purposes only. No allowance will be made for pool heaters for residential customers.

8. Temporary Service

Extensions for temporary service or for operations, which in the opinion of the Utility are of a speculative character or of questionable permanency will not be made under this rule, but will be made in accordance with Rule No. 3.

9. Length and Location

The length of main or service required for an extension will be considered as the distance along the shortest practical and available route, as determined by the Utility, from the Utility's nearest permanent distribution main.

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When, in the judgment of the Utility, providing service to an applicant would impair service to other customers, the cost of necessary reinforcement to eliminate such impairment may be included in the cost calculation for the extension.

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The Utility will not tap a gas transmission main except when conditions in its sole opinion justify such a tap. Where such taps are made, the applicant will pay the Utility the cost of such tap, and extensions therefrom will be made in accordance with the provisions of this rule.

RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

E. GENERAL CONDITIONS *(Continued)*

12. Other Types of Connections

Where an applicant or customer requests a type of service connection other than standard such as curb meters and vaults, etc., the Utility will consider each such request and will grant such reasonable allowance as it may determine. The Utility shall install only those facilities that it determines are necessary to provide standard natural gas service in accordance with this tariff. Where the applicant requests the Utility to install special facilities which are in addition to, or in substitution for, or which result in higher costs than the standard facilities which the Utility would normally install, the extra cost thereof shall be borne by the applicant.

13. Excess Flow Valve and Service Line Shut-off Valve Installation N

The installation of an Excess Flow Valve (EFV) or Service Line Shut-off Valve (SLSV) shall be performed on all newly installed or replaced service pipes connected to the Utility's distribution system before the service is activated as provided by this Rule. Nothing in this Rule prevents the Utility from installing or specifying, in its sole discretion, the installation of an EFV or a SLSV in additional service types. N

D

a. Applicable service line types. N

(1) A single service line to one single-family residence;

(2) A branched service line to a single-family residence (SFR) installed concurrently with the primary SFR service line (i.e. a single EFV may be installed to protect both service lines);

(3) A branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV;

(4) Multifamily residences with known customer loads not exceeding 5,500 SCFH per service at time of service installation based on installed meter capacity; N

D/L

D/L

RULE NO. 6

SERVICE AND MAIN EXTENSIONS
(Continued)

E. GENERAL CONDITIONS *(Continued)*

12. Other Types of Connections

Where an applicant or customer requests a type of service connection other than standard such as curb meters and vaults, etc., the Utility will consider each such request and will grant such reasonable allowance as it may determine. The Utility shall install only those facilities that it determines are necessary to provide standard natural gas service in accordance with this tariff. Where the applicant requests the Utility to install special facilities which are in addition to, or in substitution for, or which result in higher costs than the standard facilities which the Utility would normally install, the extra cost thereof shall be borne by the applicant.

13. Excess Flow Valve and Service Line Shut-off Valve Installation N

The installation of an Excess Flow Valve (EFV) or Service Line Shut-off Valve (SLSV) shall be performed on all newly installed or replaced service pipes connected to the Utility's distribution system before the service is activated as provided by this Rule. Nothing in this Rule prevents the Utility from installing or specifying, in its sole discretion, the installation of an EFV or a SLSV in additional service types.~~In accordance with The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 and Title 49, Sections 192.381,192.383 and 192.385 of the Code of Federal Regulations, the installation of an Eexcess Fflow Vvalve (EFV) or Manual Service Line Shut-off Valve (MSV), as defined in Rule No. 1, shall be performed by the Utility on all newly installed or replaced single residence service lines connected to its distribution system before the service line is activated. If any other customer requests the installation of an excess flow valve, the Utility shall perform the installation subject to the feasibility of such installation and the customer assuming responsibility for all costs associated with installation.~~ N D D

a. Applicable service line types. N

(1) A single service line to one single-family residence;

(2) A branched service line to a single-family residence (SFR) installed concurrently with the primary SFR service line (i.e. a single EFV may be installed to protect both service lines);

(3) A branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV; N

(4) Multifamily residences with known customer loads not exceeding 5,500 SCFH per service at time of service installation based on installed meter capacity; N | N

~~14. Exceptional Cases~~ D/L

~~In unusual circumstances, when the application of this Rule appears impractical or unjust to either party, the Utility or the applicant may refer the matter to the Commission for special ruling or for the approval of special conditions which may be mutually agreed upon, prior to commencing construction.~~

~~15. Taxes Associated with Nonrefundable Contributions and Advances~~

~~Any federal, state or local income taxes resulting from a nonrefundable contribution or advance by the customer in compliance with this rule will be recorded as a deferred tax and appropriately reflected in the Utility's rate base. These deferred taxes will be amortized over the remaining tax life of the asset.~~ D/L

RULE NO. 6

SERVICE AND EXTENSIONS
(Continued)

E. GENERAL CONDITIONS *(Continued)*

13. Excess Flow Valve and Service Line Shut off Valve Installation *(Continued)*

a. Applicable service line types. *(Continued)*

(5) A single, small commercial customer served by a single service line with a known customer load not exceeding 5,500 SCFH, at the time of meter installation, based on installed meter capacity; and,

(6) For service lines with meter capacity that exceeds 5,500 SCFH, a SLSV or, if possible, based on sound engineering analysis and availability, an EFV, shall be installed.

b. The Utility is not required to install an EFV if one or more of the following conditions are present:

(1) The service line does not operate at a pressure of 10 psig or greater throughout the year;

(2) The Utility has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a customer;

(3) An EFV could interfere with the necessary operation or maintenance activities such as blowing liquids from the line; or

(4) An EFV meeting the performance standards in 49 C.F.R. § 192.381 is not commercially available to the Utility.

c. The Applicant shall provide the Utility information concerning the gas usage and demand requirements. The EFV or SLSV will be designed and constructed so that suitable gas capacity is available and satisfactory to the Utility.

d. The Utility will construct, own, operate and maintain the EFV or SLSV in connection with the service line installation.

N
N

RULE NO. 6

SERVICE AND EXTENSIONS
(Continued)

E. GENERAL CONDITIONS *(Continued)*

13. Excess Flow Valve and Service Line Shut off Valve Installation *(Continued)*

a. Applicable service line types. *(Continued)*

(5) A single, small commercial customer served by a single service line with a known customer load not exceeding 5,500 SCFH, at the time of meter installation, based on installed meter capacity; and,

(6) For service lines with meter capacity that exceeds 5,500 SCFH, a SLSV or, if possible, based on sound engineering analysis and availability, an EFV, shall be installed.

b. The Utility is not required to install an EFV if one or more of the following conditions are present:

(1) The service line does not operate at a pressure of 10 psig or greater throughout the year;

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(3) An EFV could interfere with the necessary operation or maintenance activities such as blowing liquids from the line; or

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N

RULE NO. 6

SERVICE AND EXTENSIONS
(Continued)

E. GENERAL CONDITIONS *(Continued)*

13. Excess Flow Valve and Service Line Shut off Valve Installation *(Continued)*

e. The Utility shall pay for all costs associated with the installation, replacement or maintenance of the EFV or SLSV unless the work is made necessary by the relocation of a main or service line that is due solely to meet the Customer's convenience, or the work is made to redress a Customer's violation of any of the Utility's tariffs, or is an additional service line for a single premise as described in Rule 6(E)(a).

f. The Customer has the right to request that an EFV be installed on their exisiting service line if the load does not exceed 5,500 SCFH and the conditions in part 13(b) are not present. In such instances, the Utility shall notify the Customer of the following:

(1) Any costs associated with the installation that shall be paid by the Customer.

(2) The Company shall install the EFV at a mutually agreeable date.

g. If a Customer requests the installation of an EFV on their exsting service line, the Utility shall perform the installation subject to the practicability of the installation at a mutually agreeable date. N

14. Exceptional Cases L

In unusual circumstances, when the application of this Rule appears impractical or unjust to either party, the Utility or the applicant may refer the matter to the Commission for special ruling or for the approval of special conditions which may be mutually agreed upon, prior to commencing construction.

15. Taxes Associated with Nonrefundable Contributions and Advances

Any federal, state or local income taxes resulting from a nonrefundable contribution or advance by the customer in compliance with this rule will be recorded as a deferred tax and appropriately reflected in the Utility's rate base. These deferred taxes will be amortized over the remaining tax life of the asset. L

RULE NO. 6

SERVICE AND EXTENSIONS
(Continued)

E. GENERAL CONDITIONS *(Continued)*

13. Excess Flow Valve and Service Line Shut off Valve Installation *(Continued)*

e. The Utility shall pay for all costs associated with the installation, replacement or maintenance of the EFV or SLSV unless the work is made necessary by the relocation of a main or service line that is due solely to meet the Customer's convenience, or the work is made to redress a Customer's violation of any of the Utility's tariffs, or is an additional service line for a single premise as described in Rule 6(E)(a).

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RULE NO. 7

PROVISION OF SERVICE

A. UTILITY RESPONSIBILITY

1. The Utility shall be responsible for the safe transmission and distribution of gas until it passes the point of delivery to the customer. Where the Utility owns and operates a meter, regulator, pipe, fixtures, apparatus, etc. downstream of the point of delivery, the Utility shall be responsible for the Utility's equipment as provided for in this Rule.

2. All meters, regulators, service pipe, fixtures, and other apparatus, etc. owned and operated by the Utility upon the customer's premises for the purpose of delivering or metering gas to the customer shall continue to be the property of the Utility, and may be repaired, replaced or removed by the Utility at any time. Such equipment installed on customer's premises shall be maintained in safe operating condition by the Utility.

3. The Utility shall not be responsible for any loss or damage occasioned or caused by the negligence or wrongful act of the customer or any of his agents, employees or licensees in installing, maintaining, using, operating, interfering with, or failing to support or protect any such meters, regulators, gas piping, appliances, fixtures or apparatus, etc.

4. The customer shall provide a leak tight system for receiving gas. The
Utility shall perform a leak check on the customer's piping system when T
the gas is turned on. If any uncontrolled hazardous leakage exists at the T
time of turn-on, service will be denied until the customer has eliminated all
such leaks. The Utility may also refuse service until a certificate executed by T
an authorized public official is issued. Except as provided in this Rule, the N
Utility has no duty to inspect, maintain, or repair the customer's premises and
has no duty to warn of any condition it observes thereon; the Utility shall not
be liable for any failure to inspect, maintain, or repair the customer's premises
or for the failure to warn of any condition. N
D

RULE NO. 7

PROVISION OF SERVICE

A. UTILITY RESPONSIBILITY

1. The Utility shall be responsible for the safe transmission and distribution of gas until it passes the point of delivery to the customer. Where the Utility owns and operates a meter, regulator, pipe, fixtures, apparatus, etc. downstream of the point of delivery, the Utility shall be responsible for the Utility's equipment as provided for in this Rule.

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4. The customer shall provide a leak tight system for receiving gas. The Utility shall perform a leak check on the customer's piping system when the gas is turned on. If any uncontrolled hazardous leakage exists at the time of turn-on, service will be denied until the customer has eliminated all such leaks. The Utility may also refuse service until a certificate executed by an authorized public official is issued. Except as provided in this Rule, the Utility has no duty to inspect, maintain, or repair the customer's premises and has no duty to warn of any condition it observes thereon; the Utility shall not be liable for any failure to inspect, maintain, or repair the customer's premises or for the failure to warn of any condition.~~The Utility has the right but not the obligation to refuse service to any customer or discontinue service with or without notice if, in the Utility's opinion, the facilities beyond the point of delivery are unsafe or present a hazardous or potentially hazardous condition.~~

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RULE NO. 7

PROVISION OF SERVICE
(Continued) T

B. CUSTOMER RESPONSIBILITY

1. The customer shall, at the customer's sole risk and expense, furnish, install and keep in good, safe and leak free condition a customer piping system, and all appliances, alarms, fixtures, and apparatus of any kind or character located beyond the point of delivery which may be required for receiving gas from the Utility and for applying and utilizing gas, including all necessary protective appliances and suitable housing therefore. T T N N

2. The customer will be solely responsible for any injury, damage or loss resulting from the gas, or its use or loss, after such gas passes beyond the point of delivery, and the Utility shall not be responsible for any loss, injury or damage occasioned or caused by the negligence or wrongful act of the Customer or any of the Customer's agents, employees or licensees in installing, maintaining, using, operating or interfering with any such customer piping system, appliances, alarms, fixtures or apparatus. Where the Utility owns and operates a meter, regulator, pipe, fixtures, apparatus, etc., downstream of the point of delivery, the customer shall not be responsible for the injury, damage, or loss resulting from the gas, or its use or loss caused by that Utility equipment except as provided in paragraph (3), below. N N N

3. No rent or other charge whatsoever will be made by the customer against the Utility for placing or maintaining said meters, regulators, service pipe, fixtures, etc., upon the customer's premises. All meters will be sealed or soldered by the Utility, and no such seal or solder shall be tampered with or broken except by a representative of the Utility appointed for that purpose. The customer shall exercise reasonable care to prevent the meters, regulators, service pipe, fixtures, etc., of the Utility upon said premises from being injured or destroyed, and shall refrain from interfering with the same and, in case of defect therein or damage thereto shall be discovered, shall promptly notify the Utility thereof. The customer shall reimburse the Utility for the cost of repairs arising from the customer's neglect, carelessness, misuse or abuse.

RULE NO. 7

PROVISION OF SERVICE
(Continued)

B. CUSTOMER RESPONSIBILITY

1. The customer shall, at the customer's sole risk and expense, furnish, install and keep in good, ~~and~~ safe and leak free condition a~~all regulators,~~ customer piping system, and all appliances, alarms, fixtures, and apparatus of any kind or character located beyond the point of delivery which may be required for receiving gas from the Utility and for applying and utilizing gas, including all necessary protective appliances and suitable housing therefore.

2. The customer will be solely responsible for any injury, damage or loss resulting from the gas, or its use or loss, after such gas passes beyond the point of delivery, and the Utility shall not be responsible for any loss, injury or damage occasioned or caused by the negligence or wrongful act of the Customer or any of the Customer's agents, employees or licensees in installing, maintaining, using, operating or interfering with any such customer piping system, appliances, alarms, fixtures or apparatus. Where the Utility owns and operates a meter, regulator, pipe, fixtures, apparatus, etc., downstream of the point of delivery, the customer shall not be responsible for the injury, damage, or loss resulting from the gas, or its use or loss caused by that Utility equipment except as provided in paragraph (3), below.

3. No rent or other charge whatsoever will be made by the customer against the Utility for placing or maintaining said meters, regulators, service pipe, fixtures, etc., upon the customer's premises. All meters will be sealed or soldered by the Utility, and no such seal or solder shall be tampered with or broken except by a representative of the Utility appointed for that purpose. The customer shall exercise reasonable care to prevent the meters, regulators, service pipe, fixtures, etc., of the Utility upon said premises from being injured or destroyed, and shall refrain from interfering with the same and, in case of defect therein or damage thereto shall be discovered, shall promptly notify the Utility thereof. The customer shall reimburse the Utility for the cost of repairs arising from the customer's neglect, carelessness, misuse or abuse.

RULE NO. 7

PROVISION OF SERVICE
(Continued)

G. CURTAILMENT *(Continued)*

Priority 4: Industrial requirements for boiler fuel use at less than 30,000 therms per peak day, but more than 15,000 therms per peak day, where alternate fuel capabilities can meet such requirements.

Priority 5: Industrial requirements for large volume (30,000 therms per peak day or more) boiler fuel use where alternate fuel capabilities can meet such requirements.

3. In the event of isolated incidents in order to avoid hazards and protect the public, the Utility may temporarily interrupt service to certain customers without regard to priority or any other customer classification.

4. The Utility shall not be responsible for any damage or claim of damage attributable to the aforementioned curtailment.

H. CONSTRUCTION STANDARDS AND SAFETY

1. The Utility shall fulfill its responsibility for warning and for the safe distribution of gas by designing, constructing, testing, inspecting, operating, and maintaining its transmission and distribution systems upstream of the point of delivery in compliance with the Federal Safety Standards for intrastate natural gas pipeline facilities and the Commission's safety standards for natural gas pipeline facilities.

2. When Utility owned and operated equipment is located downstream of the point of delivery:

   a. The Federal Safety Standards for intrastate natural gas pipeline facilities and the Commission's safety standards for natural gas pipeline facilities do not apply to the customer piping system. T

RULE NO. 7

PROVISION OF SERVICE
(Continued)

G. CURTAILMENT *(Continued)*

Priority 4: Industrial requirements for boiler fuel use at less than 30,000 therms per peak day, but more than 15,000 therms per peak day, where alternate fuel capabilities can meet such requirements.

Priority 5: Industrial requirements for large volume (30,000 therms per peak day or more) boiler fuel use where alternate fuel capabilities can meet such requirements.

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2. When Utility owned and operated equipment is located downstream of the point of delivery:

   a. The Federal Safety Standards for intrastate natural gas pipeline facilities and the Commission's safety standards for natural gas pipeline facilities do not apply to the customer piping system. T

RULE NO. 8

METER READING
(Continued)

C. CUSTOMER REQUESTED METER TESTS (Continued)

2. In the event the customer should at any time request that the meter be tested by an independent certified testing agency mutually accepted by all parties, the customer shall be directly responsible to and shall be charged by said independent testing agency for the full costs of such test, unless the meter is inaccurate in excess of 3 percent, in which case the Utility shall be liable for such cost. Further, in this regard, the customer shall be notified in advance as to the existence of this provision and the nature of the charge herein provided.

D. FACILITIES ON CUSTOMER'S PREMISES

1. Meter Installation

   a. All meters will be installed by the Utility in some convenient location approved by the Utility and so placed as to be at all times accessible for inspection, reading and testing. The Utility will change the meter location on customer's premises for reasonable cause but when such request is made solely to suit the customer's convenience, or to overcome unsafe conditions other than those caused by the Utility, a charge may be made to cover the actual cost of the change.

   b. In all buildings in which separate meters are hereafter required to be installed for various floors or groups of rooms in order to measure the gas supplied to each tenant, the Utility may require all meters to be located at a central point, and each such meter will be clearly marked to indicate the particular location supplied by it.

D

RULE NO. 8

METER READING
(Continued)

C. CUSTOMER REQUESTED METER TESTS (Continued)

2. In the event the customer should at any time request that the meter be tested by an independent certified testing agency mutually accepted by all parties, the customer shall be directly responsible to and shall be charged by said independent testing agency for the full costs of such test, unless the meter is inaccurate in excess of 3 percent, in which case the Utility shall be liable for such cost. Further, in this regard, the customer shall be notified in advance as to the existence of this provision and the nature of the charge herein provided.

D. FACILITIES ON CUSTOMER'S PREMISES

1. Meter Installation

   a. All meters will be installed by the Utility in some convenient location approved by the Utility and so placed as to be at all times accessible for inspection, reading and testing. The Utility will change the meter location on customer's premises for reasonable cause but when such request is made solely to suit the customer's convenience, or to overcome unsafe conditions other than those caused by the Utility, a charge may be made to cover the actual cost of the change.

   b. In all buildings in which separate meters are hereafter required to be installed for various floors or groups of rooms in order to measure the gas supplied to each tenant, the Utility may require all meters to be located at a central point, and each such meter will be clearly marked to indicate the particular location supplied by it.

   ~~c. The Utility, at its convenience, may install Automatic Meter Reading (AMR) or Offsite Meter Reading (OMR) devices on the customer's premises. When such a request is made solely for the convenience of the customer, a charge will be assessed for the actual cost of the device including installation.~~ D

RULE NO. 8

METER READING
(Continued)

D. FACILITIES ON CUSTOMER'S PREMISES (*Continued*)

2. Utility Easements and Rights of Ingress and Egress T

a. Upon application for gas service and the establishment of service pursuant thereto, and upon the taking of service at any time thereafter, the customer shall be deemed to grant to the Utility and its successors and assigns, to whatever extent the customer may be empowered to make such grant, a perpetual easement and irrevocable license for the installation and maintenance of a gas pipeline or pipelines and appurtenances across, over, under and through the customer's premises, together with rights of ingress and egress and any temporary easements reasonably necessary to install, maintain, or replace the Utility's gas facilities. The terms of the grant are such that the Utility may, in conjunction with Rule 7(A)(2), relocate its gas facilities and the easement and license to a different location on the premises in order to continue to provide service to the customer or customers served by the Company's gas facilities. Any such grant from the owner of the premises serviced shall be deemed to be an easement running with the land, and shall bind his heirs and assigns. T T N N

b. The Utility shall at all times have the right of ingress to and egress from the customer's premises at all reasonable hours for any purpose reasonably connected with the furnishing of gas, and the exercise of any and all rights secured to it by law or these rules.

D/L

D/L

RULE NO. 8

METER READING
(Continued)

D. FACILITIES ON CUSTOMER'S PREMISES (*Continued*)

2. Utility Easements and Rights of Ingress and Egress~~Utility's Right of Ingress to and Egress from the Customer's Premises~~ T

a. Upon application for gas service and the establishment of service pursuant thereto, and upon the taking of service at any time thereafter, the customer shall be deemed to grant to the Utility and its successors and assigns, to whatever extent the customer may be empowered to make such grant, ~~an~~ a perpetual easement and irrevocable ~~easement~~ license for the installation and maintenance of a gas pipeline or pipelines and appurtenances across, over, under~~upon~~ and through the customer's premises, together with rights of ingress and egress and any temporary easements reasonably necessary to install, maintain, or replace the Utility's gas facilities ~~for the location of the facilities of the Utility required to provide service~~. The terms of the grant are such that the Utility may, in conjunction with Rule 7(A)(2), relocate its gas facilities and the easement and license to a different location on the premises in order to continue to provide service to the customer or customers served by the Company's gas facilities. Any such grant from the owner of the premises serviced shall be deemed to be an easement running with the land, and shall bind his heirs and assigns. T T N N

b. The Utility shall at all times have the right of ingress to and egress from the customer's premises at all reasonable hours for any purpose reasonably connected with the furnishing of gas, and the exercise of any and all rights secured to it by law or these rules.

~~c. The Utility shall have the right (but not the obligation) to remove any or all of its property installed on the customer's premises at the termination of service.~~ D/L

~~E. SERVICE CONNECTIONS MADE BY UTILITY'S EMPLOYEES~~

~~Only duly authorized employees or agents of the Utility are allowed to connect the service pipe to, or disconnect the same from the Utility's gas facilities, or to install, or establish service at the meter or regulator assembly.~~ D/L

RULE NO. 8

METER READING
(Continued)

D. FACILITIES ON CUSTOMER'S PREMISES (*Continued*)

2. Utility Easements and Rights of Ingress and Egress (Continued) T

c. Upon the Utility's request, an applicant for gas service shall provide, without cost to the Utility, a non-exclusive perpetual easement in a form and upon terms that are satisfactory to the Utility for the installation and maintenance of a gas pipeline or pipelines and appurtenances, across, over, under, and through the applicant's premises, together with the rights of ingress and egress and any temporary easements that are reasonably necessary for the Utility to install, maintain, or replace the Utility's gas facilities. If the applicant is not the property owner, then the applicant shall secure such easements from the property owner. The Utility may request such easements whenever it determines that its existing easements or other property rights are unsatisfactory. Failure to provide such easements may be grounds for refusal of service. An easement or other property right may be unsatisfactory if, among other things, it burdens the Utility with undue costs (including costs related to indemnification, insurance, or the maintenance and restoration of the burdened estate); fails to provide a safe, convenient, and economical means for the placement, operation, or access to the Utility's gas facilities; seeks to confer benefits for the applicant or a customer that are unjust, unreasonable, unjustly discriminatory, or preferential; is vague or ambiguous; or conflicts with this Tariff or with the Commission rules and regulations. N

d. The Utility shall have the right (but not the obligation) to remove any or all of its property installed on the customer's premises at the termination of service. T/L L L

e. If the customer is currently receiving service, then within ten (10) days of the Utility's request, the customer shall provide, without cost to the Utility, a non-exclusive perpetual easement as described in paragraph (c). If the customer is not the property owner, then the customer shall secure such easement from the property owner. The Utility may request such an easement whenever it determines that its existing easement or other property rights are unsatisfactory. Failure to provide such easements shall be grounds for termination of service as provided in Rule 10C. N

RULE NO. 8

METER READING
(Continued)

D. FACILITIES ON CUSTOMER'S PREMISES (*Continued*)

2. Utility Easements and Rights of Ingress and Egress~~Utility's Right of Ingress to and Egress from the Customer's Premises~~ (Continued) T

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RULE NO. 8 L

METER READING
(Continued)

E. SERVICE CONNECTIONS MADE BY UTILITY'S EMPLOYEES

Only duly authorized employees or agents of the Utility are allowed to connect the customer piping system to, or disconnect the same from, the Utility's gas facilities, or to turn on the Utility's supply of gas. T L/T

RULE NO. 8

METER READING
(Continued)

L

E. SERVICE CONNECTIONS MADE BY UTILITY'S EMPLOYEES

Only duly authorized employees or agents of the Utility are allowed to connect the customer piping system ~~service pipe~~ to, or disconnect the same from, the Utility's gas facilities, ~~or to install,~~ or to turn on the Utility's supply of gas~~establish service at the meter or regulator assembly~~. T L/T

RULE NO. 9

BILLING AND COLLECTION
(Continued)

O. ELECTRONIC BILLING

Electronic Billing is an optional billing service whereby customers may elect to receive, view, and pay their gas bills electronically. An electronic bill may be generated in lieu of a paper bill under the following conditions: D

1. Customers requesting this service may be required to complete additional forms and agreements with the Utility and/or the Electronic Billing Service Provider. D

2. Electronic Billing may be discontinued at any time by the Utility, the customer or the Electronic Billing Service Provider. T

3. Except as otherwise provided in this section, all other provisions of the Utility's Rules and Regulations as contained in this Arizona Gas Tariff are applicable to Electronic Billing and made a pad hereof. T

RULE NO. 9

BILLING AND COLLECTION
(Continued)

O. ELECTRONIC BILLING

Electronic Billing is an optional billing service ~~for residential sales customers~~ whereby customers may elect to receive, view, and pay their gas bills electronically. An electronic bill may be generated in lieu of a paper bill under the following conditions: D

1. Customers requesting this service may be required to complete additional forms and agreements with the Utility and/or the Electronic Billing Service Provider.

~~2. Customers must use a third party Electronic Billing Service Provider.~~ D

~~3~~2. Electronic Billing may be discontinued at any time by the Utility, the customer or the Electronic Billing Service Provider. T

~~4~~3. Except as otherwise provided in this section, all other provisions of the Utility's Rules and Regulations as contained in this Arizona Gas Tariff are applicable to Electronic Billing and made a pad hereof. T

RULE NO. 10

TERMINATION OF SERVICE
(Continued)

A. NONPERMISSIBLE REASONS TO DISCONNECT SERVICE *(Continued)*

g. Residential service to ill, elderly, or handicapped persons who have an inability to pay will not be terminated until all of the following have been attempted:

(1) The customer has been informed of the availability of funds from various government and social assistance agencies

(2) A third party previously designated by the customer has been notified and has not made arrangements to pay the outstanding Utility bill.

h. A customer utilizing the provisions of (f) or (g) above may be required to enter into a deferred payment agreement with the Utility within ten days after the scheduled termination date.

i. The gas service will not be discontinued for nonpayment under any circumstances on the day prior to a national holiday or weekend.

j. Disputed bills where the customer has complied with the Commission's rules on customer bill disputes.

B. TERMINATION OF SERVICE WITHOUT NOTICE

1. The Utility has the right, but not the responsibility, to terminate service without advance written notice under the following conditions: T

a. For unsafe apparatus or where service is detrimental or damaging to the Utility, its customers, or the general public.

RULE NO. 10

TERMINATION OF SERVICE
(Continued)

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RULE NO. 10

TERMINATION OF SERVICE
(Continued)

B. TERMINATION OF SERVICE WITHOUT NOTICE *(Continued)*

(1) If any unsafe or hazardous condition is found to exist on the customer's premises, or if the use of gas thereon by apparatus, appliances, equipment, or otherwise is found to be detrimental or damaging to the Utility, its customers, or the general public, or if the utilization of gas by means thereof is prohibited or forbidden by law, the service may be disconnected without notice. The Utility will attempt to notify the customer or occupant immediately of the reasons for the discontinuance and the corrective action to be taken by the customer before service can be restored.

(2) Except as provided in Rule No. 7, the Utility does not assume T
the duty of inspecting the customer piping system, appliances, T
alarms, fixtures, or apparatus of any kind or character located
beyond the point of delivery, including any necessary protective T
appliances and suitable housing therefore, and assumes no liability therefore.

b. For Fraud

The Utility shall have the right to refuse or to discontinue gas service if the acts of the customer or the conditions upon his premises are such as to indicate intention to defraud the Utility. When the Utility has discovered that a customer has obtained service by fraudulent means, or has used the gas service for unauthorized purposes, the service to that customer may be discontinued without notice. The Utility will not restore service to such customer until that customer has complied with all filed rules and reasonable requirements of the Utility and the Utility has been reimbursed for the full amount of the service rendered and the actual cost to the Utility incurred by reason of the fraudulent use.

c. Unauthorized resale or use of Utility services.

d. Failure of a customer to comply with the curtailment procedures imposed by the Utility during supply shortages.

2. The Utility shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Utility.

3. The Utility shall maintain a record of all terminations of service without notice. This record will be maintained for a minimum of one year and shall be available for inspection by the Commission.

RULE NO. 10

TERMINATION OF SERVICE
(Continued)

B. TERMINATION OF SERVICE WITHOUT NOTICE *(Continued)*

(1) If any unsafe or hazardous condition is found to exist on the customer's premises, or if the use of gas thereon by apparatus, appliances, equipment, or otherwise is found to be detrimental or damaging to the Utility, its customers, or the general public, or if the utilization of gas by means thereof is prohibited or forbidden by law, the service may be disconnected without notice. The Utility will attempt to notify the customer or occupant immediately of the reasons for the discontinuance and the corrective action to be taken by the customer before service can be restored.

(2) Except as provided in Rule No. 7, t~~T~~he Utility does not assume the duty of inspecting the customer piping system, ~~regulators,~~ appliances, alarms, fixtures, or apparatus of any kind or character located beyond the point of delivery, including any~~all~~ necessary protective appliances and suitable housing therefore, and assumes no liability therefore. T T T

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RULE NO. 10

TERMINATION OF SERVICE
(Continued)

C. TERMINATION OF SERVICE WITH NOTICE

1. The Utility has the right, but not the responsibility, to terminate service to any customer for any reason stated below provided the Utility has met the notice requirements established by the Commission: T

   a. Customer violation of any of the Utility's tariffs.

   b. Failure of the customer to pay a delinquent bill for Utility service.

   c. If a customer is receiving gas service at more than one location, service at all locations may be discontinued if bills for service at any one or more of these locations are not paid within 25 days, provided the Utility has given the customer at least five days' prior written notice of such intention. However, domestic residential service will not be discontinued because of nonpayment of bills for other classes of service.

   d. Failure to meet or maintain the Utility's deposit requirements.

   e. If, for the convenience of an applicant, the Utility should establish gas service to an applicant before he has established his credit, the Utility may discontinue service if the applicant fails to establish credit within five days thereafter.

   f. Use of restricted apparatus.

   g. Failure of the customer to provide the Utility reasonable access to its equipment and property.

   h. Customer breach of a written contract or agreement for service or service-related work between the Utility and customer.

   i. When necessary for the Utility to comply with an order of any governmental agency having such jurisdiction.

   j. Failure to provide an easement in a form and upon terms that are satisfactory to the Utility for the installation and maintenance of a gas pipeline or pipelines and appurtenances as provided in Rule No. 8. N N N

2. The Utility shall maintain a record of all terminations of service with notice. This record shall be maintained for one year and be available for Commission inspection.

RULE NO. 10

TERMINATION OF SERVICE
(Continued)

C. TERMINATION OF SERVICE WITH NOTICE

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Southwest Gas Corporation

DOCKET NO. G-01551A-19-0055

2019 General Rate Case

Testimony

Vol. 2 of 3

May 1, 2019

Southwest Gas Corporation

DOCKET NO. G-01551A-19-0055
2019 General Rate Case

Volume 2

TAB	WITNESS
1	Matthew D. Derr
2	Byron C. Williams
3	Kevin M. Lang
4	John R. Olenick
5	Carla D. Ayala
6	Kristien M. Tary
7	Dane A. Watson
8	Randi L. Cunningham
9	Theodore K. Wood
10	Robert B. Hevert

May 1, 2019

Tab 1

Direct Testimony
of
Matthew D. Derr

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-19-0055

PREPARED DIRECT TESTIMONY
OF
MATTHEW D. DERR

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 1, 2019

Table of Contents
of
Prepared Direct Testimony
of
MATTHEW D. DERR

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
MATTHEW D. DERR

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Matthew D. Derr. My business address is 1600 E. Northern Avenue, Phoenix Arizona 85020.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) as the Director of the Regulation and Energy Efficiency Department.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 No.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I provide an overview of the Company's application for rate relief. Additionally, I discuss the currently authorized Customer Owned Yard Line (COYL) and Vintage Steel Pipe (VSP) infrastructure recovery mechanisms and the Company's request to implement a new infrastructure recovery mechanism associated with its proposed 7000/8000 Pipe Replacement Program. I also support the Company's proposed tariff changes.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The primary drivers necessitating the Company's application for rate relief – namely, its level of capital investments since the its last general rate case, and the need to incorporate the effects of the Tax Cuts and Jobs Act of 2017 (Tax Reform);
- A discussion of the Company's currently authorized infrastructure recovery mechanisms, including proposed modifications to the VSP Plan of Administration (POA);
- The Company's proposal to implement a 7000/8000 Pipe Replacement Program, including its proposal for a new infrastructure recovery mechanism, and its proposed POA;
- The Company's proposal to consolidate the Company's infrastructure recovery mechanism surcharges into a single surcharge; and
- Changes to the Company's Arizona Gas Tariff to reflect current business practices and Pipeline and Hazardous Materials Safety Administration (PHMSA) rule changes, as well as to correct minor inconsistencies and incorporate non-substantive housekeeping edits.

II. OVERVIEW OF THE NEED FOR RATE RELIEF

Q. 7 Why is Southwest Gas filing for rate relief?

A. 7 As discussed in more detail in the prepared direct testimony of Company witness Randi L. Cunningham, since the end of the last test period - November 30, 2015 the Company has invested approximately $667 million to provide safe and reliable service to Arizona customers. Additionally, as discussed in more detail in the prepared direct testimony of Company witness Byron C. Williams, the

Company is flowing back to customers the benefit of lower federal income taxes from Tax Reform. Customers are benefiting from Tax Reform in three ways in this case. First, the Company's cost of service reflects federal taxes at the lower 21 percent marginal tax rate. Second, as described by witnesses Cunningham and Williams, the Company is proposing a methodology to reduce the Company's cost of service through the amortization of Accumulated Excess Deferred Income Taxes (AEDIT). Finally, in Decision No. 76798, the Commission approved a one-time volumetric credit to reflect the approximately $20 million reduction in the Company's cost of service from tax reform. During 2018, the Company refunded approximately $18.1 million to customers. The difference of $1.8 million is being returned to customers as part of this case.

III. INFRASTRUCTURE PROGRAMS

COYL

Q. 8 Is the Company proposing any modifications to its COYL Program?

A. 8 No. The COYL Program continues to meet the objectives outlined by the Commission in Decision Nos. 72723, 74304, and 76069. Since the inception of the COYL program, the Company has relocated more than 21,000 COYLs in the state.

VSP

Q. 9 Is the Company proposing any modifications to its VSP Replacement Program?

A. 9 Yes. While the VSP Replacement Program has performed as intended by allowing the Company to proactively replace approximately 155 miles of pre-1970 VSP in Arizona, while at the same time balancing the rate impact to the Company's customers, Southwest Gas seeks to make two revisions to the VSP

POA. First, the Company proposes to modify the VSP POA to reflect the appropriate Rate of Return for the VSP Replacement Program. Second, the Company proposes to add two FERC accounts to the list of eligible FERC accounts for recovery in the VSP Replacement Program - Accounts 378 (Measuring and Regulator Stations) and Account 385 (Industrial Measuring and Regulating Station Equipment).

Q. 10 Why is Southwest Gas requesting to modify the Rate of Return calculation reflected in the VSP POA?

A. 10 Currently, the VSP POA utilizes the Fair Value Rate of Return (FVROR) approved in the Company's last general rate case to calculate the VSP surcharge. As discussed more fully in the prepared direct testimony of Company witness Theodore K. Wood, applying the FVROR established in the last general rate case to new incremental investments in rate base (such as the VSP replacements), results in an under recovery of capital costs and generates a revenue deficiency that renders the rates recovered through the mechanism unjust and unreasonable. In addition, the prepared direct testimony of Company witness Randi L. Cunningham explains that while calculating the incremental FVROR on incremental plant is the most appropriate method for developing the revenue requirement on incremental investments between rate cases, application of either the incremental FVROR or the Weighted Average Cost of Capital (WACC) will result in just and reasonable rates. Accordingly, the Company seeks to modify the VSP surcharge calculation to include the incremental FVROR or, alternatively, the WACC.

Q. 11 Why is Southwest Gas requesting that FERC Accounts 378 and 385 be added to the VSP POA?

A. 11 The continued accelerated replacement of pre-1970's VSP will accomplish a number of key operational objectives, including modernizing the Company's steel pipe facilities to current industry safety standards and enhancing the safety and reliability of the distribution and transmission systems through improved record keeping and documentation regarding pipeline construction practices, material selection, material and pipeline testing. Through the process of replacing distribution and transmission VSP, the Company has recognized system enhancements and operational efficiencies such as: 1) minimizing the amount of high pressure pipe needed to serve an area; 2) replacing pipe in a manner that improves reliability and redundancy by standardizing operating pressures; 3) reducing the need for pressure reinforcements; 4) minimizing the number of facilities in its system requiring high levels of maintenance; and 5) replacing pipe to future system requirements such as pipe location, size, and operating pressures based upon future customer growth.

The Company is proposing to include the costs associated with certain pressure regulating station replacements in the VSP Replacement Program when the replacements occur in association with VSP replacement work and add operational efficiencies or provide additional system reliability advantages, such as those discussed above. These replacements may include situations where pressure regulation stations are upgraded, relocated, or abandoned as part of system reconfigurations associated with VSP work. These pressure regulation stations would not be replaced if not for the VSP work being done as part of the VSP Replacement Program.

Q. 12 Is the Company's request to add these FERC accounts consistent with the terms of the VSP POA?

A. 12 Yes. I believe the absence of these accounts was simply an oversight by the parties as the VSP POA contemplates the replacement of other facilities that need to be replaced in order to effectuate the VSP replacement. Also, the VSP POA specifically states that the list of VSP Eligible FERC accounts may be revised or expanded to accommodate changes or new accounts approved by the Commission.

<u>7000/8000 Pipe Replacement</u>

Q. 13 Describe the Company's proposal for a 7000/8000 Pipe Replacement Program.

A. 13 As described in more detail in the prepared direct testimony of Company witness Kevin M. Lang, the proposed 7000/8000 Pipe Replacement Program involves the proactive evaluation and, where necessary, replacement of certain 7000/8000 Driscopipe installed in the Company's Arizona distribution system prior to 2001.

Q. 14 What is the Company's proposed cost recovery for the 7000/8000 Pipe Replacement Program?

A. 14 The Company proposes that cost recovery for the 7000/8000 Pipe Replacement Program function in a manner similar to the cost recovery for the currently authorized COYL and VSP Replacement Programs. Annually, the Company will file an application with the Commission seeking authority to adjust a surcharge to recover the revenue requirement on the capital investment and O&M costs associated with the 7000/8000 Pipe Replacement Program. Similar to the existing COYL program, the amounts used to calculate the surcharge will be equal to the depreciation, O&M and authorized pre-tax rate of return on rate base associated with the actual investment costs. Please refer to Exhibit No._(MDD-1) for the Company's proposed POA for the 7000/8000 Pipe Replacement Program.

Q. 15 What customer protections are included in the 7000/8000 Pipe Replacement Program surcharge proposal?

A. 15 The Company proposes to limit the annual rate changes for the surcharge to $0.01 per therm per year, in line with the annual per therm limitation in the COYL program.

Q. 16 What is the expected bill impact of this $0.01 per therm annual rate limitation?

A. 16 For a single family residential customer, the bill impact would be approximately $0.24 per month.

Q. 17 Has Southwest Gas considered consolidating its three infrastructure-related surcharges?

A. 17 Yes. The Company is amenable and believes there may be value to consolidating the COYL, VSP and 7000/8000 surcharges into a single surcharge related to gas infrastructure replacement. By way of analogy, the Company does not have a surcharge for each of its energy efficiency programs; rather, there is a single DSM surcharge that recovers the costs of various energy efficiency program costs that are each tracked separately. Similarly, with respect to the various infrastructure programs, costs can continue to be tracked and recorded by individual program (COYL, VSP, 7000/8000) and instead of maintaining separate charges for each program, we could consolidate them into a single Gas Infrastructure Recovery Charge to simplify the charges for customers.

<u>IV. PROPOSED TARIFF CHANGES</u>

Q. 18 Please describe the Company's proposed changes to its Arizona Gas Tariff.

A. 18 In addition to a variety of housekeeping changes to clarify its tariff and correct minor inconsistencies, Southwest Gas is proposing tariff modifications to reflect changes to its business practices, clarify customer responsibilities with regard to utility easements, clarify the scope of services Southwest Gas provides to its customers, and incorporate PHMSA rule changes with respect to Excess Flow Valves (EFV). The Company's proposed revised tariff, in both redline and clean versions, is included in Volume I of the application.

Q. 19 Please describe the proposed revisions to Rule 3B with respect to interest on customer deposits.

A. 19 The current interest rate on customer deposits of six percent has not been modified in a number of years and is not in line with current interest rates or the customer deposit provisions by Arizona electric utilities. The Company is proposing to use the one-year U.S. Treasury Constant Maturities rate, effective on the first business day of the year, as published on the Federal Reserve Website, and to update this rate annually. This is more in line with the customer deposit provisions approved by the Commission for APS and TEP.

Q. 20 Please describe the proposed revisions to Rule 6 with respect to facilities extensions.

A. 20 These revisions allow for a refund period of ten years for all facilities extension projects. This provides a uniform refund period for all projects and is consistent with the time generally required for developers to complete projects. By establishing a longer time horizon under which developers can qualify for a refund of an advance, they have a greater opportunity to establish and grow the permanent natural gas load necessary for the long-term success of their projects. These revisions also allow customers to receive the appropriate credit for additional verified incremental permanent load connected to a facilities extension. Currently, the tariff prohibits refunds for such incremental load for additional customers that connect to a facilities extension, or a series of facilities extensions, that were not contemplated in the original extension. Southwest Gas believes these changes will provide additional flexibility for developers and customers and support economic development in the State.

Q. 21 Please describe the proposed revisions to Rules 3C, 8D and 10C with respect to utility easements and the utility's right of ingress and egress.

A. 21 These revisions are intended to clarify the customer's obligation to provide the Company access for its natural gas facilities whenever the Company provides service through facilities that are installed on the customer's premises.

Q. 22 Please describe the proposed revisions to Rules 3C, 7A, 7B, 8E, 10B and 10C with respect to utility and customer responsibilities.

A. 22 These revisions are intended to clarify the Company's service obligations and provide a clear expectation of the scope of services that the Company provides to its customers.

Q. 23 Please describe the proposed revisions to Rule 9 with respect to EFVs.

A. 23 On October 21, 2016, PHMSA issued its Final Rule amending 49 CFR 192.381, 192.383 and 192.385 to expand the existing requirements for the installation of EFVs on new or replaced service lines to single-family residences. This expansion includes: 1) new or replaced branched service lines to single-family residences; 2) new or replaced service lines to multi-family residences; 3) small commercial entities consuming gas volumes not exceeding 1,000 standard cubic feet per hour (SCFH); and 4) the installation of EFVs or service line shut-off valves (e.g., curb valves) on service lines with meter capabilities exceeding 1,000 SCFH. Further, the amendments to 49 CFR 192.383 allow customers to request that the utility install an EFV on an existing service line (i.e., a retrofit installation), and requires utilities to notify customers of their right to request a retrofit EFV installation. The CFR amendments went into effect April 14, 2017 and while Southwest Gas is operationally compliant, it must revise its tariff to correspond with these pipeline safety changes.

Q. 24 Does this conclude your prepared direct testimony?

A. 24 Yes.

SUMMARY OF QUALIFCATIONS
MATTHEW D. DERR

Matthew D. Derr is the Director/Regulation and Energy Efficiency for Southwest Gas Corporation (Southwest Gas). He provides strategic leadership, guidance, and direction in the alignment of the Company's regulatory strategy, ensures technical accuracy, and regulatory compliance, as well as ensuring the Company has positive relationships with all regulatory stakeholders.

Mr. Derr joined Southwest Gas in 2012 as an Administrator in the Corporate Public Affairs Department in Phoenix. He was subsequently promoted to Regulatory Manager/Arizona in 2015 and his current role in May 2018.

Prior to joining Southwest Gas, Mr. Derr worked in several senior positions in state government, including as a Policy Advisor at the Arizona Corporation Commission. He holds a Bachelor of Arts Degree in Economics from Arizona State University.

SOUTHWEST GAS CORPORATION

SOUTHWEST GAS CORPORATION

7000/8000 PIPE REPLACEMENT PROGRAM

PLAN OF ADMINISTRATION

This Plan of Administration (Plan) describes how Southwest Gas Corporation (Southwest Gas or Company) administers the 7000/8000 Cost Recovery Mechanism as initially approved in Docket No. G-01551A-19-0055, Decision No. xxxxx.

May 1, 2019

Version: Original
Cancelling: ______

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I. DEFINITIONS

A. **Commission**: The Arizona Corporation Commission.

B. **Rate Adjustment Mechanism**: A Commission-approved provision that allows the Company to increase and decrease a certain rate or rates, in an established manner, when increases and decreases in specific costs are incurred by the Company.

C. **7000/8000 Pipe Replacement Program Cost Recovery Mechanism (CRM)**: The Rate Adjustment Mechanism designed to recover the revenue requirement associated with the 7000/8000 Pipe Replacement Program.

II. PURPOSE

The CRM provides for the recovery of the revenue requirement associated with M7000/8000 incremental operations and maintenance (O&M) costs and replacements performed under the 7000/8000 Pipe Replacement Program.

In Docket No. G-01551A-19-0055 (Decision No. xxxxx), the Commission established a program for Southwest Gas to proactively evaluate and, if necessary, replace certain M7000/8000 Driscopipe installed in the Company's Arizona distribution system prior to 2001. The Program provides the Company with O&M to perform enhanced field inspections on this population of pipe. When pipe meets certain criteria, it will be replaced, and those costs included for recovery in the CRM.

III. APPLICABLE RATE SCHEDULES

The CRM is applicable to the Company's tariffed rate schedules, excluding G-30 Optional Gas Service, Special Contracts, and SB-1 Standby Gas Service.

IV. FILING PROCESS

By February 28 of each year, Southwest Gas will file an application with the Commission to adjust the CRM and provides an Annual Report to document the progress of the program. No later than 45 days after the Company's filing Staff will review the filing and make its recommendation to the Commission, with the goal of having new, Commission-approved CRM rates in place effective June 1.

At a minimum, the Annual Report will include the following information for the previous calendar year:

1. An overview of the Program.
2. Results of the enhanced field patrols surveys.
3. The miles of M7000/8000 pipe replaced.

V. ACCOUNTING

The costs associated with the Company's M7000/8000 replacements are charged to the appropriate FERC accounts. The revenue requirement associated with the M7000/8000 replacements is recovered through the CRM.

The CRM is based solely on actual costs and costs eligible for recovery, which are O&M costs, depreciation and pre-tax return. The original cost pre-tax rate of return authorized by the Commission is applied to gross plant, less accumulated depreciation and less Accumulated Deferred Income Taxes related to the plant cost incurred under this program. Depreciation expense includes actual recorded depreciation expense at the currently authorized depreciation rate per year for services, applied on a monthly basis to M7000/8000 replacement plant as of the previous month-end.

The change in the CRM surcharge shall not exceed $0.01 per therm in any single year.

Calculation of the revenue requirement included in the CRM terminates upon inclusion of the 7000/8000 costs in base rates as the result of being included in rate base in a general rate case.

The Company shall provide to Staff a surcharge schedule and supporting schedules, showing a detailed calculation of the revenue requirement and the surcharge will be included in the Company's annual application for cost recovery.

Please refer to Exhibit 1 for a calculation illustrating the mechanics of the CRM.

VI. RATE ADJUSTMENT

Pursuant to Decision No. xxxxx, the CRM surcharge rate is adjusted annually.[1]

Sheet 1 CRM calculation uses applicable therms 12-months ending December 31. Negotiated contract therms are exempt from the CRM calculation.

VII. PLAN REVISION PROCESS

This Plan will periodically be reviewed for accuracy. Any necessary revisions will be filed with the Commission.

[1] Please refer to Exhibit 1 for an example of the calculation and supporting documents.

SOUTHWEST GAS CORPORATION
ARIZONA
M7000/8000 REPLACEMENT PROGRAM
SURCHARGE CALCULATION
AS OF DECEMBER 31, 2019
PROJECTED EFFECTIVE DATE JUNE 01, 2020

Line No.	Description	Reference	Amount	Line No.
	(a)	(b)	(c)	
1	FV Gross M7000/8000 Plant Installed [1]	Company Records	$	1
2	FV Accumulated Provision for Depreciation	Company Records		2
3	FV Net M7000/8000 Plant	Ln 1 + Ln 2	$ -	3
4	FV Accumulated Deferred Income Taxes	Company Records		4
5	M7000/8000 FV Rate Base	Ln 3 + Ln 4	$ -	5
6	Return and Taxes on M7000/8000 Rate Base	Incremental Pretax FVROR [2] * Ln 5		6
7	O&M Expense	Company Records		7
8	Depreciation Expense	Company Records		8
9	Revenue Requirement	Ln 6 + Ln 7 + Ln 8	$ -	9
10	Sales and Full Margin Transportation Volumes [1]	Company Records		10
11	Surcharge	Ln 9 / Ln 10	$	11

[1] Total sales and full margin transportation volumes applicable to the M7000/8000 Surcharge.
[2] The authorized pretax FVROR is recalculated to include only the fair value increment resulting from the

Tab 2

Direct Testimony of Byron C. Williams

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-19-0055

PREPARED DIRECT TESTIMONY
OF
BYRON C. WILLIAMS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

MAY 1, 2019

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Prepared Direct Testimony
of

BYRON C. WILLIAMS

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
Byron C. Williams

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Byron C. Williams. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Tax Department. My title is Director/Tax.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously provided testimony to the Federal Energy Regulatory Commission, the Public Utilities Commission of Nevada and the Arizona Corporation Commission (Commission).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 The purpose of my prepared direct testimony is to provide information concerning Southwest Gas' federal income tax, and state and local taxes as they relate to this proceeding.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The Company's calculation of the federal income tax expense and the impact of the Tax Cuts and Jobs Act (TCJA) on the calculation of federal income taxes;
- The Company's calculation and treatment of excess accumulated deferred income taxes;
- The application of the Modified Business Tax; and
- An update on the Company's Property Tax Mechanism.

II. INCOME TAXES AND THE TCJA

Q. 7 What federal income tax rate was used in calculating the Company's proposed income tax expense in this Docket?

A. 7 Southwest Gas utilized the current federal income tax rate of 21 percent in its calculations. This rate is the result of the December 2017 enactment of the TCJA. As part of the TCJA, the corporate federal income tax rate was changed from 35 percent to 21 percent, effective January 1, 2018. The reduced federal income tax rate of 21 percent was applied to both current and deferred federal income taxes for the test period.

Q. 8 What other significant changes resulted from the TCJA?

A. 8 The TCJA does not allow bonus depreciation on depreciable property used in providing the Company's utility services, if placed in service after September 27, 2017 (with some exceptions). As such, bonus depreciation was not calculated for any utility property not eligible for bonus depreciation. Where bonus depreciation was not calculated for depreciable property, Modified Accelerated Cost Recovery System (MACRS) tax depreciation rates were utilized.

III. EXCESS ACCUMULATED DEFERRED INCOME TAXES

Q. 9 What is Excess Accumulated Deferred Income Taxes (EADIT)?

A. 9 EADIT is the portion of deferred tax liability that existed at the end of 2017 (calculated at the 35 percent federal income tax rate) that will never be paid to the federal government because the tax rate was reduced to 21 percent. At the end of 2017 the income tax deferred liability accounts were revalued assuming a 21 percent federal tax rate. The EADIT was reclassified from the deferred income tax liability account to a regulatory liability account, to be refunded to customers.

Q. 10 What are plant-related (protected) and non-plant (unprotected) EADIT?

A. 10 Plant-related EADIT is the portion of the total EADIT that is associated with the cumulative book/tax differences of depreciable property. The Company treats all plant-related EADIT as protected, and therefore subject to the IRS normalization rules and violation penalties. Non-plant EADIT is total EADIT less plant-related EADIT and is not subject to the IRS normalization rules and violation penalties.

Q. 11 What is the balance of the Company's protected and unprotected EADIT?

A. 11 The Arizona plant-related EADIT balance is approximately $191 million. The Arizona non-plant EADIT balance is approximately ($1 million).

Q. 12 How will the Company's EADIT be returned to customers?

A. 12 The Company proposes to adjust the revenue requirement by the test period amount of amortization allowed by the IRS for the plant-related protected EADIT. In addition, the Company proposes to adjust the revenue requirement to fully amortize the non-plant EADIT over a typical rate case cycle. These adjustments are addressed in the prepared direct testimony of Company witness Randi L. Cunningham.

Q. 13 Why must Southwest Gas return plant-related EADIT to customers over time, rather than immediately?

A. 13 The TCJA penalizes a utility that returns plant-related EADIT to customers more rapidly or to a greater extent than the amount computed using the Average Rate Assumption Method (ARAM). A refund in excess of ARAM limitations is called a normalization violation. The estimated turnaround required by ARAM for the Company's plant-related EADIT is approximately 40 years (the book life of the underlying property).

Q. 14 What are the penalties of a normalization violation if the EADIT is returned to customers too quickly?

A. 14 The penalties for a normalization violation are severe and include the following: (1) a current tax penalty equal to the amount by which the utility returned the EADIT to customers more rapidly than permitted under the ARAM; and (2) the utility will no longer be able to claim accelerated depreciation for income tax purposes. These penalties would reduce cash flow, causing increased borrowing costs and future customer rate increases.

Q. 15 What is the ARAM?

A. 15 Under federal income tax law provisions, the ARAM is the methodology used to calculate the maximum amount of EADIT returned to customers without triggering normalization violation penalties. Please refer to the prepared direct testimony of Company witness Randi L. Cunningham for details regarding the amortization of EADIT included in the Company's cost of service.

Q. 16 How does the ARAM calculate the amortization of plant-related EADIT?

A. 16 The ARAM calculation consists of two-parts: (1) the utility calculates the ratio of aggregate deferred taxes for the property to the aggregate timing differences for the property; and (2) the percentage ratio calculated is multiplied by the amount of timing differences turning around during the year.

Q. 17 Can the Company amortize its Arizona plant-related EADIT using the Reverse South Georgia (RSGM) methodology?

A. 17 No. The TCJA requires the ARAM limitation to be applied to any refund of plant-related EADIT, unless the utility is unable to identify when book/tax differences originate and reverse. The Company has sufficient historical records to track this information and, as such, is required to apply the ARAM limitation. Any alternative methodology (e.g., RSGM) that exceeds the ARAM limit subjects the Company to penalties.

Q. 18 Has the Company begun to amortize its plant or non-plant related EADIT since the implementation of the TCJA?

A. 18 No. Southwest Gas has not recorded any amortization of its EADIT for Arizona in the Company's financial statements. The Company will begin to amortize its Arizona EADIT upon receiving a decision with the effective date of rates in this rate case.

Q. 19 What are some of the benefits of the Company's proposed treatment of its EADIT?

A. 19 The proposed methodology ensures that all eligible EADIT is returned to customers. It also ensures that the amortization of the EADIT for financial statement purposes matches the period in which the EADIT is returned to customers. The Company will reduce the EADIT regulatory liability recorded in its financial statements as the EADIT is returned to customers. The proposed approach and use of the ARAM methodology also mitigates any potential normalization violations as defined by the Internal Revenue Code and associated Treasury Regulations.

Q. 20 Have any of the Company's other rate jurisdictions agreed with this proposed methodology for the amortization of EADIT?

A. 20 Yes. The Public Utilities Commission of Nevada implemented the same methodology proposed by the Company herein, commencing in January 2019.

IV. MODIFIED BUSINESS TAX

Q. 21 Are any additional taxes included in Southwest Gas' application?

A. 21 Yes. The Company included a jurisdictional allocation of the common portion of its Modified Business Tax (MBT) liability.

Q. 22 How is the MBT calculated?

A. 22 The MBT is based on total gross wages, less employee health care benefits paid by the employer, and less a statutory deduction amount. This amount is then multiplied by a tax rate of 1.475%. The Company calculates this amount separately for employees who work at corporate headquarters in Las Vegas, Nevada but perform job functions that benefit the entire Company in all its jurisdictional service territories – similar to other system allocable expenses.

Q. 23 Why is a portion of the MBT being allocated to Arizona?

A. 23 Because a portion of the MBT liability is a cost of the corporate function, it should be allocated as a common expense amongst all jurisdictions. The Company proposes that the relevant portion be allocated to Arizona using the 4-factor methodology.

V. PROPERTY TAX MECHANSIM

Q. 24 Please describe Southwest Gas' Property Tax Mechanism.

A. 24 The Property Tax Mechanism was approved by the Commission in the Company's last general rate case, and helps the Company address the volatility associated with the Arizona property tax liability between rate cases. Because property values and tax rates are determined by state and local governments and are beyond the control of the Company, it is appropriate for changes in property tax expense to be deferred, then collected or refunded in the next rate case over a typical rate case cycle. The Property Tax Mechanism is a symmetrical mechanism. Therefore, if the Arizona property tax expense is above the amount authorized, there will be a charge to customers and if the Arizona property tax expense decreases, there will be a credit to customers. As such, the Property Tax Mechanism ensures that customers never pay more than the actual property tax expense that is paid by the Company.

Q. 25 Is Southwest Gas proposing any changes to its Property Tax Mechanism in this proceeding?

A. 25 No. The Company believes that the Property Tax Mechanism is operating as the Commission intended. As of January 31, 2019, the end of the test period for this proceeding, the Company had a regulatory liability balance of approximately $6.8 million that will be refunded to customers.

Q. 26 Does this conclude your prepared direct testimony?

A. 26 Yes.

SUMMARY OF QUALIFICATIONS
BYRON C. WILLIAMS

I am a graduate of Brigham Young University having received a Bachelor of Science in Accounting in 2001. In 2003, I earned a Master's in Business Taxation from the University of Southern California.

In 2002, I joined the tax department of PricewaterhouseCoopers LLP in Los Angeles, California. In 2010, I joined the Las Vegas office and was promoted to Director in 2011. In 2013, I joined Southwest Gas as Director/Tax. I am responsible for all phases of the Company's taxes, including preparation of all federal, state, and local tax returns and tax provisions, researching tax matters and preparation of tax-related testimony and exhibits for rate proceedings, including rate cases.

I have been licensed as a Certified Public Accountant by the state of California since 2007. In 2011, I was also licensed as a Certified Public Accountant by the state of Nevada. I am also a member of the American Institute of Certified Public Accountants, as well as the Nevada Society of CPAs.

Tab 3

Direct Testimony
of
Kevin M. Lang

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-19-0055

PREPARED DIRECT TESTIMONY
OF
KEVIN M. LANG

ON BEHALF OF
SOUTHWEST GAS CORPORATION

MAY 1, 2019

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of
Prepared Direct Testimony
of
KEVIN M. LANG

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
KEVIN M. LANG

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Kevin Lang. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Engineering Services department. My title is Director/Engineering Services.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Arizona Corporation Commission (Commission), the California Public Utilities Commission, and the Public Utilities Commission of Nevada.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor, from an operations perspective, the Company's proposal to implement a program for the replacement of 7000/8000 plastic pipe that is not performing as expected.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony focuses on the Company's proposal to proactively evaluate and, as necessary, replace 7000 and 8000 Driscopipe pipe throughout the Company's Arizona service territory that is not performing as expected.

<u>II. 7000/8000 PIPE REPLACEMENT PROGRAM</u>

Q. 7 Please describe Southwest Gas' proposed 7000/8000 Pipe Replacement Program.

A. 7 The Company's proposed 7000/8000 Pipe Replacement Program involves the proactive replacement of certain 7000 and 8000 Driscopipe installed in the Company's Arizona distribution system prior to 2001. Southwest Gas has observed material degradation in its Arizona 7000 and 8000 Driscopipe inventory, including some degradation that has resulted in leakage. While the Company has efforts in place to evaluate the degradation when pipe is exposed during normal field excavations, the proposed 7000/8000 Pipe Replacement Program will allow the Company to proactively assess a larger portion of its 7000 and 8000 Driscopipe inventory through enhanced field inspections. As necessary, the Program will also allow the Company to replace 7000 and 8000 Driscopipe before the degradation results in a leak.

Q. 8 What is Driscopipe?

A. 8 Driscopipe is the brand name for Phillips Driscopipe, Inc. and its predecessor company Phillips Products Company. The brand name Driscopipe is still in use today. Driscopipe is a polyethylene (PE) plastic pipe type that has been installed in natural gas systems since the 1960s. The family of Driscopipe that is known to be installed in Southwest Gas' Arizona system includes Driscopipe model 7000 and 8000 pipe (collectively 7000/8000 pipe). In Southwest Gas' Arizona system, 7000/8000 pipe is used for distribution pressure mains and services, typically between one-half inch and six inches in diameter and was installed between 1974 and 2000. The Company has approximately 10,804 miles of 7000/8000 pipe in its Arizona service territory as of December 31, 2018.

Q. 9 Are there potential safety and reliability concerns with the 7000/8000 pipe?

A. 9 Yes. Safety and reliability concerns have been expressed by PHMSA regarding the potential for material degradation in Driscopipe 8000. In an Advisory Bulletin issued in March 2012[1], PHMSA noted that material degradation has been identified on 8000 pipe that was installed from 1978 through 1999 in desert-like environments in the southwestern United States. While the Advisory Bulletin does not identify a root cause for the material degradation, PHMSA notes that all reported cases have occurred in southwestern United States locations where the average ambient temperatures are very high. PHMSA advocates for the use of accelerated and more frequent leak surveys in areas where degraded pipe is known or expected to exist. In addition, PHMSA encourages operators with the pipe to work with all stakeholders, including regulatory agencies, to determine how to address discovery and repair/replacement.

Southwest Gas has also identified potential safety and reliability concerns with this pipe and has been monitoring material degradation since approximately 2005. The Company has provided the Commission's Pipeline Safety Staff with frequent updates on 7000/8000 pipe material degradation since approximately 2010. As of March 2019, the Company has experienced 129 known leaks on

[1] PHMSA Docket No. PHMSA-2012-0044, ADB-2012-03: *Pipeline Safety: Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation (Notice)*. A copy is provided as Exhibit No.__(KML-1).

7000/8000 pipe in its Arizona distribution system due to material degradation. All leaks experienced to date have resulted from material degradation of the inner pipe wall (internal degradation). A copy of the Company's material internal degradation-based leaks in its Arizona service territory as of March 14, 2019, is provided in Exhibit No.__(KML-2).

Q. 10 What is material degradation?

A. 10 Material degradation of PE pipe occurs when components in the plastic pipe known as antioxidants, meant to extend the life of the pipe and inhibit aging, are depleted. This leads to the pipe becoming dry and brittle. Material degradation can be found on the outside of the pipe, classified as external material degradation, or the inside of the pipe, classified as internal material degradation. Southwest Gas has observed both internal and external material degradation in 7000 and 8000 pipe within its Arizona service territory.

Q. 11 How is Southwest Gas currently addressing 7000/8000 pipe material degradation?

A. 11 As indicated above in Q/A 9, the Company has been monitoring material degradation within its population of 7000/8000 pipe since approximately 2005. As part of the Company's Distribution Integrity Management Program (DIMP), more frequent leak surveys, leak patrols and pipe replacement/abandonment have been implemented to mitigate the threat of material degradation.

Starting in 2015, the Company began the proactive process of evaluating samples of degraded pipe in the Company's laboratory using sophisticated material equipment capable of determining the extent of material degradation throughout the wall of the sample pipe in question. This evaluation identified that material degradation does not appear to occur homogeneously throughout pipe, but primarily from the outer-wall-inward or the inner-wall-outward.

Southwest Gas currently collects samples of degraded 7000/8000 pipe whenever material degradation is witnessed when the pipe is exposed in the field. Exposure may occur due to pipeline excavations associated with normal field activities such as new facility installations, field repairs, or other operations and maintenance activities.

Q. 12 What is Southwest Gas proposing in this Application regarding the 7000/8000 Pipe Replacement Program?

A. 12 As discussed in Q/A 11, the Company has identified locations were 7000/8000 pipe is not performing as expected. The Company has made progress on replacing or abandoning inactive services and stubs, but this represents a small percentage of the overall 7000/8000 pipe population. Given the amount of 7000/8000 pipe in Arizona, the Company requires additional tools to monitor and, if needed, replace the pipe when it is found to not perform as expected.

Southwest Gas seeks authority through the 7000/8000 Pipe Replacement Program proposal to proactively monitor and evaluate 7000/8000 pipe through enhanced field inspections. If these inspections show that the pipe isn't performing as expected, it will be replaced. The intent of the Program is to replace the pipe that is experiencing material degradation and not performing as expected, before leakage occurs. The Company is proposing a surcharge to recover the costs associated with the 7000/8000 Pipe Replacement Program. Please refer to the prepared direct testimony of Matthew D. Derr for the Company's cost recovery proposal.

Q. 13 Is the 7000/8000 Pipe Replacement Program proposal similar to its COYL program approved in the Company's 2010 Rate Case?

A. 13 Yes. The Company's Customer Owned Yard Line (COYL) program was developed to allow the Company to perform proactive field evaluations to identify leaking COYLs and the subsequently replace them. The Company's proposed 7000/8000 Pipe Replacement Program will use similar proactive field investigations to identify those 7000/8000 facilities that are not performing as expected and replace them before leakage occurs.

Q. 14 Is the existing process of collecting samples for material testing sufficient to understand the extent of material degradation on the Company's entire population of 7000/8000 pipe in Arizona?

A. 14 No. While the Company is taking prudent and reasonable actions to proactively identify those portions of its 7000/8000 pipe that contain material degradation, Southwest Gas also recognizes that it only evaluates pipe for material degradation when 7000/8000 pipe is exposed for other operational and maintenance purposes and material degradation is visibly evident on the exposed pipe. As a result, the data collected currently by the Company represents a small portion of the overall population of 7000/8000 pipe in its Arizona distribution system.

The enhanced field inspections included in the Company's proposed 7000/8000 Pipe Replacement Program will provide the information necessary to learn more about this pipe condition and to more effectively assess its overall inventory of 7000/8000 pipe inventory in Arizona. This information will lead to more informed integrity management decisions regarding the frequency of leak patrols and surveys as well as pipe replacement/abandonment decisions.

Q. 15 What is the scope and purpose of the Company's planned enhanced field inspection program for 7000/8000 pipe?

A. 15 Southwest Gas currently collects samples of degraded 7000/8000 pipe whenever material degradation is witnessed when the pipe is exposed in the field. The Company recognizes that this process provides a limited view of its overall inventory of 7000/8000 pipe. As such, the proposal will provide the necessary funding to perform enhanced field inspections that will allow the Company to assess a greater portion of its 7000/8000 pipe inventory such that the pipe can be evaluated and, if necessary, replaced, without having to wait for it to be exposed during normal field activities.

The Company proposes to use field crews to perform enhanced field inspections beyond those conducted currently through normal excavation activities on its 7000/8000 pipe. These enhanced field inspections will include actions such as performing investigatory dig and inspect activities to identify external material degradation and will allow the Company to proactively assess more of this pipe than the Company can currently accommodate today.

The Company may also use other technologies and methods to gain additional information about the current condition of its 7000/8000 pipe inventory. One example of an additional technology or method is camera inspection. Camera inspection allows the company to make observations of the condition of the inside of the pipe. This information would serve to further inform the Company's integrity management program.

Q. 16 What type of work would the Company include within its enhanced field inspections?

A. 16 The enhanced field inspections would be performed by Company or Contractor resources and would be an operational and maintenance (O&M) expense. The work would include labor, equipment, material, and other costs associated with performing field excavations such as excavation permits, backfill, traffic control, and pavement restoration. Similar to the Company's existing COYL program, where certain O&M costs such as costs associated with leak survey and customer outreach are recovered using a surcharge mechanism, the Company would track these additional enhanced field collection costs and capture them as surcharge mechanism costs as further described by Company witness Matthew D. Derr.

Q. 17 Will the proposed enhanced field inspections complement the Company's DIMP?

A. 17 Yes. One of the key tenets of an operator's distribution integrity management program is system knowledge. The Federal DIMP regulations[2] require an operator to demonstrate an understanding of its gas distribution system developed from reasonably available information. The enhanced field inspections will further complement the Company's DIMP and provide additional information about the current condition of its 7000/8000 pipe inventory. Data collected could also serve to adjust and prioritize accelerated actions such as leak patrols and pipe replacement recommendations contemplated as part of the 7000/8000 Pipe Replacement Program.

[2] 49 CFR § Part 192.1007(a).

Q. 18 Is the Company currently replacing 7000/8000 pipe?

A. 18 Yes. The Company currently replaces 7000/8000 pipe in three (3) primary categories.

1. The first category involves a small subset of 7000/8000 pipe containing stubs and inactive facilities similar to those facilities which have exhibited leakage. This subset of pipe has been targeted by the Company's integrity management program for replacement since 2014.
2. The second category involves 7000/8000 pipe replaced due to non-integrity management related factors such as system reinforcements, public works projects, or other planned construction activities.
3. The third category employs a risk-based approach using material degradation testing data that is evaluated each year. This third category is the focus of the Company's proposal with regards to a proactive 7000/8000 Pipe Replacement Program.

The proposed 7000/8000 Pipe Replacement Program would expand the data available to the Company through enhanced field inspections. If the 7000/8000 pipe meets certain criteria, it will be replaced as part of the Program. The Company has made progress on replacing or abandoning inactive services and stubs, but this represents a small percentage of the overall 7000/8000 pipe inventory. Given the amount of 7000/8000 pipe in Arizona, the Company requires additional tools to monitor and, if needed, replace the pipe when it is found to not perform as expected.

Q. 19 If the Company is already conducting some level of replacement on 7000/8000 pipe, why is Southwest Gas proposing a 7000/8000 Pipe Replacement Program?

A. 19 Prior to 2015, the Company was specifically targeting 7000/8000 pipe replacement associated with the portions of its system where it actively experienced leakage due to material degradation. As indicated in Q/A 9, all of the 129 leaks in Arizona experienced by the Company, due to material degradation, have resulted from internal degradation. The external material degradation analysis that commenced in 2015 is intended to identify 7000/8000 pipe that is not performing as expected and proactively replace the pipe before it leaks.

Q. 20 Why is it important to proactively replace pipe before it leaks?

A. 20 It is prudent to replace pipe that is not performing as expected before the pipe leaks, resulting in a safety concern. Safety and reliability are Southwest Gas' top priorities and the Company consistently strives to be a leader in the natural gas industry by being a proactive and prudent operator.

Q. 21 How will the proposed 7000/8000 Pipe Replacement Program inform the Company's approach to 7000/8000 pipe?

A. 21 Information collected from enhanced field inspection activities will further define the extent of the population of 7000/8000 pipe exhibiting signs of material degradation. The enhanced field inspections will also provide additional information about past discoveries of material degradation which may include information regarding the time dependency of material degradation on those segments not performing as expected.

Q. 22 Does this conclude your prepared direct testimony?

A. 22 Yes.

SUMMARY OF QUALIFICATIONS
KEVIN M. LANG

Kevin M. Lang is the director/Engineering Services for Southwest Gas Corporation (Southwest Gas). He directs and coordinates support to five operating divisions for pipeline safety code compliance; right-of-way and land rights acquisition and maintenance, material specifications and approval; environmental policies and procedures; proper energy measurement; pipeline cathodic protection; technical support of the SCADA system; project design review; hydraulic modeling support; and the training and qualification of technical services personnel. He previously oversaw the Company's distribution integrity management program and laboratory services under the same capacity.

Mr. Lang joined Southwest Gas in 2003 as an engineer in Victorville, CA. He was subsequently promoted to distribution engineer in 2005, supervisor/Engineering in 2006 and manager/Engineering in 2007. During this period, Mr. Lang oversaw the design of transmission and distribution facilities for new business, franchise and system reinforcements; PVC pipeline replacements; pipeline safety code compliance; MAOP studies and requalification programs; and preparation of short and long-term capital budgets.

He was promoted to director/Gas Operation Support Staff in 2011 where he directed the Company's technical skills training, Operator Qualification (OQ) training and testing, tool and equipment evaluations, operations-related procedures manuals, Incident Command System training and operation of the Emergency Response Training Facilities in Tempe and Las Vegas. Mr. Lang was subsequently promoted to director/Engineering Services in November of 2012.

He holds a Bachelor of Science degree in Mining Engineering from Virginia Tech. He is a registered Professional Engineering in the state of Nevada with a proficiency in Civil

Engineering. Mr. Lang currently serves on the American Gas Association's Operations Safety Regulatory Action Committee.

(1952). Stated otherwise, a highway use tax need not necessarily be dedicated to highway purposes. As a result, the DOF's failure to demonstrate a connection between the CMV Tax and highway funding is not dispositive.

FMCSA concludes, therefore, that New York City's CMV Tax is a highway use tax within the meaning of 49 U.S.C. 14506(b)(2).

In consideration of the above, FMCSA grants the DOF's petition for reconsideration and reverses its decision preempting New York City's credential display requirement. Today's decision is limited to the new arguments the DOF raised in its petition for reconsideration claiming exception from preemption under § 14506(b)(2). Under this analysis, New York City's credential display requirement in § 11–809 is not preempted and New York City may resume enforcement.

This decision does not affect the Agency's previous determination preempting the credential display requirements in New Jersey and Cook County, Illinois.

Issued on: February 29, 2012.

Anne S. Ferro,

Administrator, Federal Motor Carrier Safety Administration.

[FR Doc. 2012–5319 Filed 3–5–12; 8:45 am]

BILLING CODE; P

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2012–0044]

Pipeline Safety: Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing this advisory bulletin to alert operators using Driscopipe® 8000 High Density Polyethylene Pipe (Drisco8000) of the potential for material degradation. Degradation has been identified on pipe between one-half inch to two inches in diameter that was installed between 1978 and 1999 in desert-like environments in the southwestern United States. However, since root causes of the degradation have not been determined, PHMSA cannot say with certainty that this issue is isolated to these regions, operating environments, pipe sizes, or pipe installation dates. While the manufacturer has attempted to communicate with known or suspected users, PHMSA and the National Association of Pipeline Safety Representatives (NAPSR) have identified several operators currently using Drisco8000 pipe who had not received communications about the issue. PHMSA is issuing this advisory bulletin to all operators of Drisco8000 pipe in an effort to ensure they are aware of the issue, communicating with the manufacturer and their respective regulatory authorities to determine if their systems are susceptible to similar degradation, and taking measures to address it.

ADDRESSES: This document can be viewed on the PHMSA home page at: *http://www.phmsa.dot.gov.*

FOR FURTHER INFORMATION CONTACT: Max Kieba by phone at 202–493–0595 or by email at *max.kieba@dot.gov.* Pipeline operators with potentially affected pipe or anyone with questions specific to actions in a certain state or region are encouraged to communicate with the appropriate pipeline safety authority directly. Operators of pipelines subject to regulation by PHMSA should contact the appropriate PHMSA Regional Office. A list of the PHMSA Regional Offices and their contact information is available at: *http://www.phmsa.dot.gov/pipeline/about/org.* Pipeline operators subject to regulation by a state should contact the appropriate state pipeline safety authority. A list of state pipeline safety authorities and their contact is provided at: *http://www.napsr.org/managers/napsr_state_program_managers2.htm.*

SUPPLEMENTARY INFORMATION:

I. Background

Two operators of natural gas pipeline systems have identified locations of material degradation on Drisco8000 pipe in Arizona and Nevada. The manufacturer of the pipe, Performance Pipe, a division of Chevron Phillips Chemical Company LP, confirmed that the pipe was degraded.

In 1999, a one-inch Copper Tube Size (CTS) Drisco8000 pipe service line in Arizona experienced a gas leak and was found to be degraded. The operator of this pipeline found areas of delaminating and surface cracking on Drisco8000 pipe ranging from one-half inch CTS to two inches Iron Pipe Size pipe at various locations in Arizona beginning in 2004. To better track the instances of the phenomenon, the operator implemented a procedure for reporting, defining the degradation area, and conducting leak surveys on the affected pipe. Chemical contamination was considered a potential source for degradation, but after extensive testing by the manufacturer and various outside laboratories, no indications of chemical source could be verified as a root cause.

In 2007, the operator experienced a gas ignition incident on a one-inch CTS Drisco8000 service line in Arizona. Due to the slit crack nature of the pipe failure, the investigation of this incident included checking for the possibility of nylon contamination in the pipe material. Nylon contamination was ruled out, but degradation of the internal pipe wall was noted. An additional incident occurred elsewhere in Arizona in 2007. As a result of these incidents, the operator implemented a replacement program and follow-up leak survey program. The operator continues its investigation and is working cooperatively with the manufacturer and regulators to determine the root causes and necessary mitigative actions.

A second operator found two cases of degraded Drisco8000 pipe in Arizona in 2006 and reported them to the Arizona Corporation Commission Office of Pipeline Safety. This operator is now looking at other areas of their service territory for potential degraded pipe issues.

The affected pipes in the cases reported thus far have diameters from one-half inch to two inches and have installation dates that range from 1978 to 1999. All reported cases have been on systems operating at or below 60 psig in desert regions in the southwestern United States. In those cases where print line codes are present on the pipe, the codes identify the pipe as being manufactured at a Watsonville, California, pipe plant which closed in 2000. The manufacturer has indicated they do not have any evidence that the condition developed as a result of the manufacturing process.

According to the manufacturer, the degraded pipe is fairly easy to identify when the pipe is exposed. Affected pipe displays delaminating or peeling of the outer diameter or a friable or crumbling appearance on the inner diameter surfaces of the pipe. In addition, an audible cracking sound or noise may be detected when flexing, cutting, or squeezing the pipe.

Once installed and in service, degraded pipe is not easy to identify. The manufacturer is not aware of a current testing protocol that consistently identifies the affected material while it is in service. Existing leak survey technologies have proven to be the most effective tool in locating and identifying degraded pipe.

The areas of degradation are not always consistent in their characteristics. The degradation may not occur along the complete pipe length, but rather may start and stop within a relatively short section of pipe and then reoccur in another area further down the segment. In addition, the operator and manufacturer have observed instances of degradation on only one side of the pipe with the other side having no indication of degradation.

The root cause of the degradation has not been determined. All reported cases have occurred in the southwestern United States where average ambient temperatures are very high, but this may or may not be a contributing factor. The manufacturer does not have evidence that the degraded pipe condition developed from or as a result of the manufacturing process. The manufacturer does not believe the issue to be associated with a particular resin lot. While a review of records has identified some changes in the resin formulation during the time period, the manufacturer does not believe that these changes contributed to the issue. The reporting operators have not identified any other construction or installation practices or conditions that are common to the known occurrences of degraded pipe.

PHMSA has asked the manufacturer to describe the problem and its extent and has requested information related to manufacturing, construction practices, and testing recommendations. Those questions and responses, along with pictures of degraded pipe, are available on the docket associated with this advisory.

The manufacturer is communicating with known customers, regulators, and industry groups as new information becomes available and the operators with known cases of degraded pipe continue to communicate with the appropriate regulatory authorities.

II. Advisory Bulletin (ADB–2012–03)

To: Operators using Driscopipe® 8000 High Density Polyethylene Pipe.

Subject: Potential for Material Degradation of Driscopipe® 8000.

Advisory: PHMSA advises all operators using Driscopipe® 8000 of the potential for material degradation. PHMSA encourages operators to communicate and work with the manufacturer and their respective regulatory authorities to consider and implement any actions that are needed to address the issue as it relates to their systems.

Operators using Drisco8000 pipe who have not already received communications from the manufacturer are encouraged to contact the manufacturer so they can receive future updates and determine whether their systems are susceptible to degradation. For additional information, contact Karen S. Lively, P.E, Technical Manager, Performance Pipe, a division of Chevron Phillips Chemical Company LP, by phone at 972–599–7413 or email at *livelks@cpchem.com.* Operators using Drisco8000 pipe are encouraged to inform the relevant regulatory authority and work together to determine what, if any, actions are needed to monitor and address the issue within their systems.

Due to the uncertainty of the root cause of the material degradation, PHMSA cannot provide specific guidance on how best to address the issue. However, PHMSA urges all operators using Drisco8000 pipe to consider the use of accelerated and more frequent leak surveys in those areas where degraded pipe is known or suspected to exist.

All operators using Drisco8000 pipe are encouraged to work with all stakeholders to determine how to address discovery and repair within their systems, taking the most conservative approach and keeping pipeline integrity and public safety a priority.

Authority: 49 U.S.C. chapter 601 and 49 CFR 1.53.

Issued in Washington, DC on February 29, 2012.

Jeffrey D. Wiese,

Associate Administrator for Pipeline Safety.

[FR Doc. 2012–5424 Filed 3–5–12; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF THE TREASURY

Treasury Inspector General for Tax Administration; Privacy Act of 1974: Computer Matching Program

AGENCY: Treasury Inspector General for Tax Administration, Treasury.

ACTION: Notice.

SUMMARY: Pursuant to 5 U.S.C. 552a, the Privacy Act of 1974, as amended, notice is hereby given of the agreement between the Treasury Inspector General for Tax Administration (TIGTA) and the Internal Revenue Service (IRS) concerning the conduct of TIGTA's computer matching program.

DATES: *Effective Date:* April 5, 2012.

ADDRESSES: Comments or inquiries may be mailed to the Treasury Inspector General for Tax Administration, Attn: Office of Chief Counsel, 1401 H St. NW., Suite 469, Washington, DC 20005, or via electronic mail to *Counsel.Office@tigta.treas.gov.*

FOR FURTHER INFORMATION CONTACT: Office of Chief Counsel, Treasury Inspector General for Tax Administration, (202) 622–4068.

SUPPLEMENTARY INFORMATION: TIGTA's computer matching program assists in the detection and deterrence of fraud, waste, and abuse in the programs and operations of the IRS and related entities as well as protects against attempts to corrupt or interfere with tax administration. TIGTA's computer matching program is also designed to proactively detect and to deter criminal and administrative misconduct by IRS employees. Computer matching is the most feasible method of performing comprehensive analysis of data.

NAME OF SOURCE AGENCY:

Internal Revenue Service.

NAME OF RECIPIENT AGENCY:

Treasury Inspector General for Tax Administration.

BEGINNING AND COMPLETION DATES:

This program of computer matches is expected to commence on March 11, 2012, but not earlier than the fortieth day after copies of the Computer Matching Agreement are provided to the Congress and OMB unless comments dictate otherwise. The program of computer matches is expected to conclude on September 11, 2013.

PURPOSE:

This program is designed to deter and detect fraud, waste, and abuse in Internal Revenue Service programs and operations, to investigate criminal and administrative misconduct by IRS employees, and to protect against attempts to corrupt or threaten the IRS and/or its employees.

Authority: The Inspector General Act of 1978, 5 U.S.C. App. 3, and Treasury Order 115–01.

CATEGORIES OF INDIVIDUALS COVERED:

Current and former employees of the Internal Revenue Service as well as individuals and entities about whom information is maintained in the systems of records listed below.

CATEGORIES OF RECORDS COVERED:

Included in this program of computer matches are records from the following Treasury or Internal Revenue Service systems.

a. Treasury Payroll and Personnel System [Treasury/DO.001]

b. Treasury Child Care Tuition Assistance Records [Treasury/DO.003]

Degraded Pipe Leaks - Arizona

No	Leak Date	MID WR Number	Printline Information	Manufacture Year	Size	Install Year	Leak Grade	Years In Service	Location	Discovery
1	30-Sep-99	42-836528	-	-	1"	1990	1	9	2710 W Bell Rd Phoenix, AZ Central Arizona - Phoenix - 42	Survey
2	28-Sep-07	42-730933	-	-	1"	1990	1	17	2710 W Bell Rd Phoenix, AZ Central Arizona - Phoenix - 42	Incident
3	4-Jan-08	34-781359	-	-	1/2"	1990	2	18	5155 Desert Sands Dr, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Odor Complaint
4	6-Aug-08	42-893962B	-	-	1"	1990	1	18	7227 S. Central Ave Unit B-6, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
5	26-Aug-08	42-902987	-	-	1"	1989	1	19	7714 W Luke Ave Glendale, AZ Central Arizona - Phoenix - 42	Survey
6	31-Aug-08	42-905995	-	-	1"	1989	1	19	5503 N 76th Dr Glendale, AZ Central Arizona - Phoenix - 42	Odor Complaint
7	2-Sep-08	42-905997	-	-	1"	1989	1	19	5515/5521 N 75th Dr Glendale, AZ Central Arizona - Phoenix - 42	Survey
8	24-Sep-08	48-915585	WA10B24SEP9427P	1994	1"	1995	1	13	14153 E 50th St Yuma, AZ Southern Arizona - Yuma - 48	Odor Complaint
9	26-Sep-08	48-915624	WA10A23MAR9315AP	1993	1"	1994	1	14	13276 E 46th Dr Yuma, AZ Southern Arizona - Yuma - 48	Odor Complaint
10	22-Oct-08	48-924254	WA10B24SEP9439	1994	1"	1995	1	13	14110 E 50th Dr, Yuma, AZ Southern Arizona - Yuma - 48	Incident
11	14-Nov-08	36-932581	WO4 11JAN83 A...	1983	2"	1983	1	25	6720 Renaissance Tucson, AZ Southern Arizona - Tucson - 36	Survey
12	4-Dec-08	34-941708	WA10A03APR90APP	1990	1/2"	1990	3	18	1803 Boulder Creek Dr Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
13	6-Mar-09	48-989816	WA10DEC0198P...	1998	1/2"	1999	1	10	12782 E 45th Dr Yuma, AZ Southern Arizona - Yuma - 48	Odor Complaint
14	19-Mar-09	42-989353	-	-	1"	1990	1	19	4820 E Ray Rd Unit A Phoenix, AZ Central Arizona - Phoenix - 42	Survey
15	4-Nov-09	34-1082696	-	-	1/2"	1989	1	20	1108 Ramar Rd, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Odor Complaint
16	15-Jan-10	42-1127253	-	-	1"	1990	1	20	7333 W Thomas Rd Unit 52 Phoenix, AZ Central Arizona - Phoenix - 42	Survey
17	20-Jan-10	34-1128253	-	-	1/2"	1990	2	20	1669 Kalil Dr. Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
18	30-Jan-10	34-1135049	WA10821FEB9403P	1994	1/2"	1994	1	16	6184 Via Del Aqua, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Odor Complaint
19	7-Apr-10	21-1164540	-	-	1"	1990	2	20	3550 Bay Sands Dr, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
20	5-May-10	36-1178557	-	-	1"	1984	1	26	2300 N. Rosemont Blvd, Tucson, AZ Southern Arizona - Tucson - 36	Survey
21	29-Sep-10	42-1235719	-	-	1"	1987	2	33	7430 S 7th St Phoenix, AZ Central Arizona - Phoenix - 42	Survey
22	3-Dec-10	42-1265943	-	-	1"	1988	1	14	6253 N 89th Ave Glendale, AZ Central Arizona - Phoenix - 42	Odor Complaint
23	13-Feb-11	42-1313945	-	-	1/2"	1988	1	23	13263 N 77th St Phoenix, AZ Central Arizona - Phoenix - 42	Odor Complaint
24	13-May-11	42-1364286	-	-	1"	1987	1	24	8027 Black Canyon Hwy Phoenix, AZ Central Arizona - Phoenix - 42	Survey
25	18-Jul-11	42-1395334	-	-	1"	1987	1	24	4150 W Peoria Ave Phoenix, AZ Central Arizona - Phoenix - 42	Survey
26	3-Nov-11	48-1442802	-	1993	1"	1994	1	17	7481 E. 24th Pl, Yuma, AZ Southern Arizona - Yuma - 48	Odor Complaint
27	8-Dec-11	48-1486676	-	-	1"	1987	1	24	10001 S. 4th Ave, Yuma, AZ Southern Arizona - Yuma - 48	Survey
28	8-May-12	48-1550158	-	-	1/2"	1997	1	15	13282 E. 54th Street, Yuma, AZ Southern Arizona - Yuma - 48	Survey
29	7-Aug-12	48-1593639	-	1992	1/2"	1992	1	20	1491 S. 4th Ave, Yuma AZ Southern Arizona - Yuma - 48	Survey
30	1-Oct-12	42-1619205	-	-	1"	1989	1	23	7900 S Autoplex Loop, Tempe, AZ Central Arizona - Phoenix - 42	Odor Complaint
31	2-Oct-12	42-1619567	-	1991	1"	1992	1	20	6828 W. Williams Dr, Glendale, AZ Central Arizona - Phoenix - 42	Odor Complaint
32	5-Oct-12	42-1620454	-	1991	1"	1992	1	20	6816 W. Crest Lane, Glendale, AZ Central Arizona - Phoenix - 42	Survey
33	5-Oct-12	42-1621247	-	1991	1"	1992	1	20	6809 W. Via Montoya Dr, Glendale, AZ Central Arizona - Phoenix - 42	Survey
34	15-Oct-12	48-1622935	-	-	1"	1988	2	24	3218 S 4th Ave, Yuma, AZ Southern Arizona - Yuma - 48	Survey
35	30-Oct-12	42-1629313	-	-	1"	1988	1	24	4825 E Warner Road, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
36	14-Nov-12	42-1634647	-	-	1"	1987	1	25	10135 Via Linda Unit 124, Scottsdale, AZ Central Arizona - Phoenix - 42	Odor Complaint
37	16-Nov-12	34-1636188B	-	1989	1/2"	1989	1	23	5288 Tierra Linda Dr., Bullhead City, AZ Southern Nevada - Bullhead City - 34	Odor Complaint
38	17-Nov-12	42-1647181	-	-	1"	1989	1	23	6100 E. Cholla Ln, Paradise Valley, AZ Central Arizona - Phoenix - 42	Survey
39	19-Dec-12	34-1653385	-	-	1"	1979	1	33	373 Anna Circle, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Odor Complaint
40	31-Dec-12	34-1666026	-	1990	1/2"	1993	1	20	1630 Aztec Road, Fort Mojave, AZ - Southern Nevada - Bullhead City - 34	Odor Complaint
41	29-Jan-13	34-1684215	-	-	2"	1993	1	20	Sunrise Vista Blvd & Vanderslice Rd, Fort Mojave, AZ Southern Nevada - Bullhead City - 34	Odor Complaint
42	29-Jul-13	48-1777792	-	1993	1"	1994	1	19	30212 E. Palo Verde Dr, Yuma, AZ Southern Arizona - Yuma - 48	Survey
43	24-Sep-13	42-1803066	-	1995	1"	1996	1	17	7444 S. Central Ave, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
44	30-Sep-13	42-1805747	-	-	1"	1987	1	26	15611 N. 59th Ave, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
45	12-Oct-13	34-1810748	-	1993	1/2"	1994	1	19	2285 Diamond Creek Rd, Fort Mojave, AZ Southern Nevada - Bullhead City - 34	Odor Complaint
46	17-Oct-13	42-1813661	-	-	1/2"	1989	1	24	4218 W. Questa Drive, Glendale, AZ Central Arizona - Phoenix - 42	Odor Complaint

Degraded Pipe Leaks - Arizona

No	Leak Date	MID WR Number	Printline Information	Manufacture Year	Size	Install Year	Leak Grade	Years In Service	Location	Discovery
47	8-Nov-13	42-1820395	-	-	1"	1986	1	27	3306 W. Osborn Rd, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
48	10-Dec-13	42-1843732A	-	-	1"	1987	1	26	2919 N. 75th Ave, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
49	17-Dec-13	42-1849178A	-	-	1/2"	1995	2	18	W Fremont Rd & 15th Ave, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
50	26-Dec-13	48-1850630	WA10A 05JAN94 4P	1994	1"	1994	1	19	10203 S Fairway Ln, Yuma, AZ Southern Arizona - Yuma - 48	Odor Complaint
51	15-Jan-14	42-1861133	-	1991	1"	1992	1	22	8958 W. Rosemont Drive, Peoria, AZ Central Arizona - Phoenix - 42	Survey
52	15-Jan-14	48-1857532	-	1998	1/2"	1999	-	15	10307 Fall Ave, Yuma, AZ Southern Arizona - Yuma - 48	Survey
53	9-Feb-14	42-1876390	WA10A19SEP9439P	1994	1"	1995	1	20	1914 E. Palomino, Gilbert, AZ Central Arizona - Phoenix - 42	Incident
54	9-Feb-14	42-1874972	WA10A19SEP9439P	1994	1"	1995	-	19	1924 E. Palomino, Gilbert, AZ Central Arizona - Phoenix - 42	Incident
55	6-Mar-14	36-1891091	-	-	1"	1991	1	23	3778 E. 43rd Place, Tucson, AZ Southern Arizona - Tucson -36	Survey
56	7-Apr-14	42-1909008	-	-	1"	1999	1	15	7439 W. Bell Rd, Peoria, AZ Central Arizona - Phoenix - 42	Survey
57	2-May-14	34-1926164	-	-	1"	1990	1	24	5626 Wishing Well Pl, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
58	3-May-14	34-1925386	-	-	1"	1990	1	24	5684 Wishing Well Pl, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
59	6-May-14	34-1925804	-	-	1/2"	1990	2	19	4460 Sharp Dr, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
60	16-May-14	34-1930211	-	-	1/2"	1994	1	20	Lot 21 Via Del Aqua Dr, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
61	21-May-14	34-1931684	-	-	1/2"	1990	1	24	Lots 22 & 23 Wishing Well Pl, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
62	2-Jun-14	34-1940789	-	-	1"	1990	2	24	5047 Sage Ln, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
63	12-Jun-14	34-1944496	WA10B 12JUL90 44B PP	1990	1/2"	1993	3	24	1642 Aztec Rd, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
64	30-Jun-14	34-1952135	WA 10B 22FEB94 03P	1994	1/2"	1994	1	20	2074 Drover Dr, Fort Mojave, AZ Southern Nevada - Bullhead City - 34	Survey
65	21-Jul-14	48-1962742	WA07A 19JUN95 16P	1995	1/2"	1995	1	19	11528 S. Glenwood Ave, Yuma AZ Southern Arizona - Yuma - 48	Survey
66	22-Jul-14	42-1962808	WT2B 15MAY92 A25 PP	1992	1"	1992	1	22	7725 S Research Dr Unit 123, Tempe AZ Central Arizona - Phoenix - 42	Odor Complaint
67	30-Jul-14	42-1971401	W10 B 27MAR88 A	1988	1/2"	1988	1	26	8600 E Broadway Rd Unit 15 Mesa, AZ Central Arizona - Phoenix - 42	Survey
68	6-Aug-14	34-1972359	WA10B 18JUL90 62A PP	1990	1/2"	1992	2	24	2066 El Rodeo Dr Space 36, Fort Mojave, AZ Southern Nevada - Bullhead City - 34	Survey
69	11-Aug-14	36-1974222	-	-	1"	1984	1	30	2304 N Rosemont Blvd, Tucson, AZ Southern Arizona - Tucson - 36	Survey
70	22-Aug-14	42-1978730A	-	-	1"	1988	1	26	2627 W Air Ln, Phoenix, AZ Central Arizona - Phoenix - 42	Odor Complaint
71	5-Sep-14	42-1987359	-	-	1/2"	1987	1	27	3406 E Nighthawk Way Phoenix, AZ Central Arizona - Phoenix - 42	Survey
72	15-Sep-14	42-1989247	WA 07A 25MAY92 19 BP	1992	1"	1992	1	22	8831 W Rimrock Dr Peoria, AZ Central Arizona - Phoenix - 42	Odor Complaint
73	19-Sep-14	42-1991508	-	-	1"	1988	1	26	3415 W. Glendale Ave, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
74	2-Oct-14	42-1997981	WA01B 03AUG96 50P	1996	1"	1997	1	17	4644 W. Villa Linda, Glendale, AZ Central Arizona - Phoenix - 42	Survey
75	10-Oct-14	42-2002724	-	-	1"	1990	1	24	15050 N. 22nd St, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
76	15-Oct-14	42-2003386	-	-	1/2"	1989	1	25	100 S Rockford Dr, Tempe, AZ Central Arizona - Phoenix - 42	Survey
77	17-Oct-14	36-2004513	-	1996	1"	1996	1	18	3830 N. Oracle Rd, Tucson, AZ Southern Arizona - Tucson - 36	Survey
78	21-Oct-14	36-2010839	-	1989	1/2"	1990	1	24	3821 W Costco Dr, Tucson, AZ Southern Arizona - Tucson - 36	Survey
79	29-Oct-14	42-2009504	-	1989	1 1/4"	1989	1	25	11430 E. Crescent Ave, Apache Junction, AZ Central Arizona - Phoenix - 42	Survey
80	19-Nov-14	42-2016943	-	-	1"	1998	1	16	5629 N. 53rd Ave, Glendale, AZ Central Arizona - Phoenix - 42	Survey
81	5-Dec-14	42-2029192	-	-	1"	1990	2	24	7831 S 14th St, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
82	5-Dec-14	36-2030246	WT 1A 06AUG89 A24 P	1989	1/2"	1990	1	24	6001 S Palo Verde Rd Unit 1, Tucson, AZ Southern Arizona - Tucson - 36	Survey
83	9-Dec-14	42-2029538	WA10 A 31MAR89 A P	1989	1/2"	1989	2	25	2650 E Superstition Blvd Unit 20, Apache Junction, AZ Central Arizona - Phoenix - 42	Survey
84	18-Dec-14	42-2033889	-	-	1"	1988	2	26	1522 E. Victory Ln, Phoenix, AZ Central Arizona - Phoenix - 42	Odor Complaint
85	7-Jan-15	42-2044762	-	-	1/2"	1987	1	28	3662 W. Van Buren St, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
86	18-Feb-15	42-2066849	-	-	1/2"	1987	1	28	7227 S 17th St, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
87	7-Jul-15	42-3015583	-	-	1/2"	1988	3	28	7323 W. Port Au Prince Rd, Peoria, AZ Central Arizona - Phoenix - 42	Survey
88	10-Jul-15	36-3005502	WA10B 14JUN92 19BP	1992	1/2"	1993	2	22	620 W. Simmons Rd, Tucson, AZ Southern Arizona - Tucson - 36	Survey
89	20-Jul-15	42-3022785	WA05B01DEC 97 13P	1997	1"	1998	1	17	7464 E. Tierra Buena Lane #107, Scottsdale, AZ Central Arizona - Phoenix - 42	Odor Complaint
90	30-Jul-15	36-3049923	-	-	1/2"	1992	1	23	3041 N Country Club Rd Unit 7, Tucson, AZ Southern Arizona - Tucson - 36	Survey
91	6-Aug-15	42-3036947	-	-	1"	1995	1	20	10596 E Penstamin Dr, Scottsdale, AZ Central Arizona - Phoenix - 42	Survey
92	24-Aug-15	42-2097939	WA07A 25MAR92 14BP	1992	1"	1992	1	23	6001 E Yucca St, Scottsdale, AZ Central Arizona - Phoenix - 42	Odor Complaint

Degraded Pipe Leaks - Arizona

No	Leak Date	MID WR Number	Printline Information	Manufacture Year	Size	Install Year	Leak Grade	Years In Service	Location	Discovery
93	24-Aug-15	42-3043216	-	-	1/2"	1987	1	28	3705 E Air Ln, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
94	10-Sep-15	36-3053426	WA01A 08JUN97 52P	1997	1"	1997	1	18	3913 N Flowing Wells Rd, Tucson, AZ Southern Arizona - Tucson - 36	Odor Complaint
95	1-Oct-15	34-3066481	WA02B25NOV9304P	1993	2"	1994	1	21	2573 Jared Drive, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
96	7-Oct-15	34-3068223	-	-	1/2"	1992	2	23	6513 Lantana Ct, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
97	22-Oct-15	42-3074695	-	-	1"	1990	2	25	16425 S. 38th Pl, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
98	23-Oct-15	42-3085659	-	-	1/2"	1985	1	31	128 W. Maricopa Fwy, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
99	1-Dec-15	42-3094916	WA 01A 07AUG95 18 P	1995	1"	1995	2	21	21822 N. Inca Ct, Sun City West, AZ Central Arizona - Phoenix - 42	Survey
100	8-Dec-15	34-3096988	-	-	1/2"	1994	3	22	13350 Waterreed Dr, Topock, AZ Southern Nevada - Bullhead City - 34	Survey
101	10-Dec-15	34-3098921	-	-	1/2"	1991	1	25	5562 Shasta Lake Dr, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
102	16-Dec-15	34-3103405	-	-	1/2"	1990	2	26	5730 Iroquois Lp, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
103	30-Dec-15	42-3105653	WA 07A 18JAN96 61 P	1996	1"	1996	2	20	5037 E. Broadway Rd, Mesa, AZ Central Arizona - Phoenix - 42	Survey
104	2-May-16	34-3190177	-	-	1/2"	1990	2	26	1928 Corry Lane, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
105	17-May-16	42-3197963	-	-	1/2"	1986	1	30	16809 S 33rd Way, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
106	28-Jul-16	36-3242350	-	-	1"	1987	1	29	3384 W Tranquility Ct, Tucson, AZ Southern Arizona - Tucson - 36	Odor Complaint
107	21-Aug-16	36-3179134	WA 10A 10APR93 16 A P	1993	1"	1994	1	22	4180 W Ina Rd Unit B, Tucson AZ Southern Arizona - Tucson - 36	Odor Complaint
108	16-Sep-16	36-3267010	-	-	2"	1989	1	27	305 E. Benson Hwy, Tucson, AZ Southern Arizona - Tucson - 36	Survey
109	1-Oct-16	42-3273442	WA 07A 17OCT92 24 B P	1992	1 1/4"	1993	1	23	5011 W Kessler Ln, Chandler, AZ Central Arizona - Phoenix - 42	Odor Complaint
110	3-Oct-16	42-3274429	WA 07A 18SEP98 P	1998	1"	1999	1	17	7131 W Ray Rd Unit 14, Chandler, AZ Central Arizona - Phoenix - 42	Odor Complaint
111	3-Oct-16	49-3273853	-	-	1 1/4"	1990	1	26	1800 15th St Unit 138, Parker, AZ Southern Nevada - Bullhead City/Parker - 49	Survey
112	3-Oct-16	34-3264010	-	-	1/2"	1994	2	22	5078 Aztec Place, Topock, AZ Southern Nevada - Bullhead City - 34	Survey
113	7-Nov-16	42-3289663	WA 05B30NOV97 42P	-	1"	1998	1	18	10719 E Posada Ave, Mesa, AZ Central Arizona - Phoenix - 42	Survey
114	18-Nov-16	42-3294006	WA 02B 23SEP93 01 P	1993	2"	1993	2	23	16400 S. 14th Ave, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
115	2-Dec-16	42-2089857	WA 10A26DEC94 52P	1994	1"	1995	2	21	15760 N Frank Lloyd Wright Blvd, Scottsdale, AZ Central Arizona - Phoenix - 42	Odor Complaint
116	15-Dec-16	32-3310447	-	-	1"	1996	3	21	512 S Eleven Mile Comer Rd, Coolidge, AZ Southern Arizona - Valley - 32	Survey
117	10-Jan-17	42-3328382	-	-	1"	1988	2	29	8952 S San Angelo St, Goodyear, AZ Central Arizona - Phoenix - 42	Survey
118	10-Jan-17	34-3328945	...DEC96	1996	1/2"	1996	3	21	2220 Rancho Colorado Blvd, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
119	3-Feb-17	34-3346065	...PE 3408 CDD...	1991	1/2"	1991	3	26	1425 Pearl Cir, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
120	16-Aug-17	34-3464301	-	-	1/2"	1994	3	23	5209 E Concho Bay, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
121	28-Aug-17	34-3468375	WA 10A 10OCT92 25 B P	1992	1/2"	1994	3	23	5072 Aravaipa Pl, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
122	7-Sep-17	42-3475462	WA 07A 19JUN93 08 A P	1993	1"	1993	1	24	9037 W Behrend Dr, Peoria, AZ Central Arizona - Phoenix - 42	Survey
123	30-Oct-17	42-3501512	WA 07A 03SEP98 P	1998	1"	1998	1	19	6831 E Flat Iron Loop, Gold Canyon, AZ Central Arizona - Phoenix - 42	Survey
124	2-Nov-17	34-3511194	-	Unknown	2"	1983	2	35	Meadows Drive and Country Club Drive, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
125	4-Dec-17	34-3526830	...WA 10A 10OCT92 25 B P...	1992	1/2"	1994	1	23	5389 Pinal Pl, Topock, AZ Southern Nevada - Bullhead City - 34	Survey
126	4-Jan-18	42-3531005	-	Unknown	1"	1986	1	31	3128 W Pima St, Phoenix, AZ Central Arizona - Phoenix - 42	Survey
127	26-Jan-18	34-3546084	-	Unknown	1/2"	1992	2	25	685 Marina Blvd, Bullhead City, AZ Southern Nevada - Bullhead City - 34	Survey
128	25-May-18	48-3635943	WA 10...COIL NO. 0164	Unknown	1/2"	1997	1	21	13805 E 52nd Dr, Yuma, AZ Southern Arizona - Yuma - 48	Survey
129	11-Oct-18	42-3722462	-	Unknown	1"	1989	1	29	2347 W Thomas Rd, Phoenix, AZ Central Arizona - Phoenix - 42	Survey

Tab 4

Direct Testimony
of
John R. Olenick

IN THE MATTER OF

SOUTHWEST GAS CORPORATION
Docket No. G-01551A-19-0055

PREPARED DIRECT TESTIMONY

OF

JOHN R. OLENICK

ON BEHALF OF

SOUTHWEST GAS CORPORATION

May 1, 2019

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of
Prepared Direct Testimony
of
JOHN R. OLENICK

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
JOHN R. OLENICK

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is John R. Olenick. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Gas Supply department. My title is Director/Gas Supply.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 Appendix A to this prepared direct testimony summarizes my educational background and relevant business experience.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Public Utilities Commission of Nevada and the California Public Utilities Commission.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 My testimony supports the Company's request to incorporate Renewable Natural Gas (RNG) purchases into its supply portfolio and include the associated costs of those purchases, as well as any revenue from the sale of environmental attributes that may be associated with the RNG, in the Company's Purchased Gas Cost Adjustment Provision.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony addresses the following key issues:

- A high-level overview of RNG and how it is produced;
- The environmental benefits associated with RNG;
- The Company's proposed Arizona RNG Program purchases;
- Potential sale of environmental attributes associated with RNG; and,
- A summary of how the proposed changes will affect the Company's customers.

II. HIGH-LEVEL OVERVIEW OF RNG PRODUCTION AND ENVIRONMENTAL BENEFITS

Q. 7 What is RNG?

A. 7 RNG is biogas that is cleaned or upgraded to pipeline quality gas by increasing the percentage of methane in the Biogas through the removal carbon dioxide and other trace components and adding a warning odorant. Biogas is defined in the Company's G-65 Tariff and in the Arizona Administrative Code R14-2-2302.3. RNG is interchangeable with natural gas and can be injected, transported, and distributed through an existing natural gas pipeline system.

Q. 8 What are potential biogas sources?

A. 8 Biogas is obtained from plant-derived organic matter, agricultural food and feed matter, wood wastes, aquatic plants, animal wastes, vegetative wastes, waste water treatment anaerobic digestion, and municipal solid waste.[1]

Q. 9 Are there currently sources of biogas in Arizona?

A. 9 Yes. Many waste water treatment plants and landfills in Arizona capture biogas to prevent the direct release of the harmful greenhouse gas, methane,

[1] See: A.A.C. R14-2-2302.3.

into the atmosphere. However, most Arizona biogas is not currently cleaned or upgraded to RNG and, therefore, is not being injected into an existing natural gas pipeline system.

Q. 10 What is the potential for RNG production in Arizona?

A. 10 University of Arizona Professor, Daniel Scheitrum, Phd, and Arizona State University Professor, Nathan Parker, Phd, estimate that the total annual RNG production from Arizona sources could reach as much as 4.28 Bcf/year. Comparatively, Southwest Gas purchases on average between 50 and 60 Bcf of natural gas, annually, for resale to its Arizona retail customers. Although the potential RNG sources are geographically diverse throughout Arizona, the majority are concentrated in the Phoenix and Tucson areas, close to Southwest Gas's existing pipeline system and load centers.[2]

Q. 11 Why is it better to capture biogas, clean it to pipeline quality RNG, and combust it if that combustion produces carbon dioxide, which is a greenhouse gas?

A. 11 If biogas is not captured, the methane released would move directly into the atmosphere. Methane is estimated to have a global warming potential that is 28 to 36 times greater than carbon dioxide.[3] Consequently, although the combustion of methane produces carbon dioxide, directly releasing methane into the atmosphere is thought to contribute more towards climate change than capturing the methane, combusting it to take advantage of the renewable energy contained in biogas, and releasing the carbon dioxide. Moreover, since the carbon in biogas comes from organic matter that fixed the carbon

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[2] See: Scheitrum, Dan, Parker, Nathan, Analysis of U.S. Supplies of RNG: Potential Impact on the LCFS through 2030, USAww Annual Meeting, Sept. 28, 2018, available at: http://www.usaee.org/usaee2018/submissions/Presentations/Scheitrum_DC18.pdf

[3] See: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

from the atmosphere, the carbon dioxide released from the combustion of biogas does not add to greenhouse gas emissions and biogas and RNG are considered carbon-neutral fuels.[4]

Q. 12 What happens to biogas produced in Arizona today?

A. 12 That depends on the plant or process that is producing biogas. Landfills and wastewater treatment plants are likely collecting the biogas produced at the facility. At a minimum, the biogas is being flared to prevent the high global warming potential methane from being released directly into the atmosphere. However, flaring wastes the energy contained in the biogas. At other sites, the biogas may be minimally cleaned and used to fire boilers or generate electricity. The heat from the boilers and electricity may be used in processes at the facility, or the electricity may be sold to produce renewable energy credits for Arizona's Renewable Energy Standard program that affects Arizona electric utilities.[5] Finally, the biogas may be cleaned and upgraded to RNG that meets pipeline specifications and then injected into a pipeline system. Any RNG that is currently being produced in Arizona is likely being transported to California where it qualifies under the Federal EPA Renewable Fuel Standard Program and California's Low Carbon Fuel Standard Program.

III. <u>SUMMARY OF THE COMPANY'S PROPOSED RNG PROGRAM</u>

Q. 13 Please describe the Company's proposed RNG Program.

A. 13 Southwest Gas seeks Commission approval to meet up to 1% of its forecasted annual Arizona retail sales with RNG purchases by 2025, 2% by 2030, and 3% by 2035. The Company would complete these purchases through a new purchase process known as the RNG Program. Further, the Company seeks Commission approval to include the cost of the RNG

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[4] See: http://biogas.ifas.ufl.edu/FAQ.asp
[5] See: A.A.C. R14-2-1801 -1816.

purchases made through the RNG Program in the Company's Purchased Gas Cost Adjustment Provision.

Q. 14 How much RNG would Southwest Gas purchase under the RNG Program?

A. 14 Although the forecasted annual Arizona throughput varies by forecast year, 1% equates to approximately 550,000 Dth annually, or about 1,500 Dth/day. By 2035, Southwest Gas's RNG purchases could reach about 1.6 Bcf annually, or about 4,500 Dth/day. Given the estimated quantities of RNG that are potentially available from Arizona sources, discussed in Q&A 10 above, it is reasonable to believe that the RNG Program level of RNG purchases could be supplied entirely from RNG sourced within Arizona.

Q. 15 Why is Southwest Gas proposing the RNG Program as part of this rate case?

A. 15 The Commission reviews the Company's gas purchases as part of a general rate case proceeding. The Company's RNG Program is an enhancement to the Company's natural gas supply portfolio and is best evaluated as part of a general rate case.

Q. 16 Where would the Company acquire supplies for the RNG Program?

A. 16 Southwest Gas believes that Arizona sourced RNG should first be explored prior to seeking RNG sources outside of Arizona. This sourcing preference will focus the environmental benefits of the RNG Program on Arizona, as well as any financial benefits from the construction of any new biogas cleaning and upgrading facilities and the ongoing operation of the upgrading facilities. Southwest Gas believes that with the Commission's recent approval of its Schedule No. G-65, Biogas and Renewable Natural Gas Services tariff provision, the Company will be able to further facilitate the development of RNG sources within Arizona by taking the RNG into its system as part of its gas supply portfolio for the benefit of all customers.

Q. Please further explain how the RNG Program would compliment Schedule No. G-65?

A. Schedule No. G-65 provides the general terms and conditions that will apply to the interconnection point between the Company's facilities and a RNG producer's facilities and specifications that the RNG must meet to be accepted into the Company's facilities. While Schedule No. G-65 facilitates the development of biogas and RNG projects in Arizona by allowing the Company to partner with developers of biogas and RNG projects, including identifying a customer or customers to take the RNG through a contracted service as part of the project, RNG development in Arizona would further benefit by allowing Southwest Gas to be a potential recipient of the RNG as part of its gas supply portfolio. .

Q. 17 Why are RNG Program purchases a goal and not a requirement?

A. 17 Most Arizona sourced biogas is not yet being upgraded to RNG and, therefore, cannot be injected into an existing natural gas pipeline system until upgrading facilities are constructed. Given that biogas upgrading facilities are capital intensive, there is no guarantee that such facilities will be built and that Arizona sourced, pipeline quality, RNG will be available to Southwest Gas. While Southwest Gas does not believe that the Commission should limit the RNG Program to only purchasing RNG from Arizona sources, Southwest Gas believes it should explore Arizona sourced RNG prior to seeking RNG sources outside of Arizona

Finally, Southwest Gas does not believe that the RNG Program should be a requirement because that would force Southwest Gas into competing with other entities who may be willing to pay more for the RNG than Southwest Gas believes is reasonable. RNG developers and suppliers could leverage such a requirement to gain a higher price than they would if there were no requirement to purchase RNG. Utilizing a goal, without a requirement, will provide Southwest Gas with the flexibility needed to enter into RNG purchase agreements at prices that are likely sufficient to spur the development of biogas upgrading facilities, but not overpriced due to a requirement to meet a specific quantity of RNG purchases by a specific date.

Q. 18 How much does RNG cost compared to conventional natural gas?

A. 18 RNG prices vary greatly depending upon the feedstock for the biogas to be upgraded, the location of the biogas source compared to the existing natural gas pipeline system, and the gas quality requirements of the pipeline that the RNG will be injected into, as well as if the RNG will qualify for credits under the Federal Renewable Fuel Standard program or California's Low Carbon Fuel Standard program. RNG that qualifies for either or both of those could be valued at $15/Dth to $50/Dth in the short-term (three to four years). However, the long-term (five years or greater) value of RNG will likely be less and be priced somewhere between $6/Dth to $15/Dth. Regardless, given the low-price environment of conventional natural gas resources, RNG prices are much higher than conventional natural gas supplies, which are likely to be around $3/Dth or less for the next five years.

Q. 19 Why is it desirable to purchase RNG at prices that are likely higher than conventional natural gas supplies?

A. 19 Given the focus of the RNG Program on Arizona sourced RNG, Southwest Gas believes that taking advantage of a renewable and sustainable Arizona resource, much of which is currently being either unutilized or underutilized, would be beneficial to Arizona environmentally and financially. The state would benefit from increased construction jobs associated with the construction of the upgrading facilities and other interconnect facilities and there would likely be more jobs associated with the operation and maintenance of the upgrading facilities. The environmental benefits of RNG are discussed in Section II above. Since very little of the biogas that is being generated in Arizona is being upgraded to RNG and displacing conventional natural gas supplies, the Company believes that the RNG Program's incremental costs would be reasonable compared to the benefits that the Company's customers, and the state as a whole, will receive. Finally, given the small amount of RNG that the RNG Program purchases would add to Southwest Gas's Arizona gas supply portfolio, the incremental cost associated with those RNG purchases would likely be immaterial. Overall, the Company believes the benefits of including RNG in its gas supply portfolio at the proposed levels justify the associated incremental costs.

Q. 20 Please explain what an Environmental Attribute is in relation to RNG?

A. 20 An Environmental Attribute is what separates RNG from conventional natural gas. The Environmental Attribute is documented through a paper trail of attestations that start with the feedstock and the process for the biogas that was produced, the location and process where the biogas was upgraded to pipeline quality RNG, the transportation of the RNG to an end user, and the final use of the RNG in some process. This paper trail is also known as a pathway. For RNG to qualify for the Federal Renewable Fuel Standard program or the California Low Carbon Fuel Standard Program, there must be approved pathways established. Environmental Attributes can make RNG more valuable than conventional natural gas, even though both are essentially methane. The process of setting up the pathways and obtaining the value for the Environmental Attributes is usually called monetizing the Environmental Attributes.

Q. 21 Would there be Environmental Attributes associated with the gas purchased through the RNG Program that could be monetized?

A. 21 Most likely yes.

Q. 22 What is the Company's proposed treatment of any funds it may receive from monetizing Environmental Attributes?

A. 22 The Company proposes to credit any funds received from monetizing Environmental Attributes directly to Account No. 191, Unrecovered Purchased Gas Costs. Consequently, any funds credited to that account will offset the price the Company paid the RNG supplier for the RNG and lower the final cost of the RNG Program to the Company's customers. This is similar to the Company's treatment of Capacity Release credits it receives when it releases unneeded interstate pipeline capacity.[6] Please refer Volume I of the Application for the proposed Special Supplementary Tariff that provides that these funds will be credited to Account No. 191.

Q. 24 Would the Commission be able to review the costs associated with RNG Program purchases?

A. 24 Yes. The Commission currently reviews all gas procurement costs for prudency and reasonableness during a general rate case. RNG Program purchases would be included in that review.

IV. RNG CUSTOMER IMPACT SUMMARY

Q. 25 What is the estimated cost to customers of the RNG Program?

A. 25 The estimated cost of the RNG Program to the average residential customer is approximately $0.26 per month for including RNG purchases at 1% of forecasted annual Arizona retail sales. The estimated monthly incremental

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[6] See, Southwest Gas Corporation Arizona Gas Tariff No. 7, Special Supplementary Tariff Interstate Pipeline Capacity Services Provision.

costs to the average residential customer for 2% and 3% are estimated to be $0.52 and $0.78, respectively.[7]

The estimated cost of the RNG Program to the average commercial customer is $1.40 per month for including RNG purchases at 1% of forecasted annual Arizona retail sales. The estimated monthly incremental costs to the average commercial customer for 2% and 3% are estimated to be $2.80 and $4.20, respectively.[8]

Q. 26 Would the potential monetization of Environmental Attributes reduce the incremental costs associated with the RNG Program?

A. 26 Yes. The incremental cost estimates do not include any funds that the Company may receive and credit back to Account No. 191 to reduce the cost of the RNG Program. It is possible that the value of the Environmental Attributes could exceed the cost the Company pays for the RNG. However, the amount of any credits the Company may receive from the monetization of Environmental Attributes will be specific to each RNG purchase, the final end use of that RNG, and the value of the Environmental Attributes available for monetization.

Q. 27 Do you believe that the Company's proposed RNG Program is prudent and reasonable?

A. 27 Yes. The RNG Program provides the Company with the ability to integrate RNG into its gas supply portfolio and would work in conjunction with the Company's recently approved Schedule No. G-65 to further leverage the development of biogas and RNG sources in Arizona. The Program does not require the Company to purchase RNG, but sets reasonable purchase

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[7] RNG purchase price assumed to be $15.00/Dth and average residential customer usage assumed to be 288 therms/year.

[8] RNG purchase price assumed to be $15.00/Dth and average commercial customer usage assumed to be 1548 therms/year, based on a weighted average of the G-25 small and medium customer classes.

targets, relating to the estimated supply of Arizona sourced RNG, that the Company will endeavor to meet. In future rate cases, the Commission would review RNG Program purchases for prudency along with all the Company's other conventional natural gas purchases. The RNG Program may spur development of Arizona RNG production and repurposes an existing energy resource that may otherwise go unused and integrates a carbon neutral energy source into the Company's gas supply portfolio.

Q. 28 Does this conclude your prepared direct testimony?

A. 28 Yes.

SUMMARY OF QUALIFICATIONS
JOHN R. OLENICK

I hold a Bachelor of Science degree in Chemistry from the University of Nevada Las Vegas and a Juris Doctorate degree from the Williams S. Boyd School of Law, University of Nevada Las Vegas. I am licensed to practice law in the State of Nevada, the United State District Court for the District of Nevada, and the United States Court of Appeals for the Ninth Circuit.

I first worked for Southwest Gas Corporation between February 1988 and June 1993. During that period I held the positions of Gas Dispatch Technician, Regulatory Analyst, and Gas Control Technician. My primary responsibilities during this period included the control and monitoring of the Southern Nevada natural gas distribution and transmission systems; analyzing gas supply and transportation contracts using linear optimization models, summarizing results, and recommending least cost alternatives; and, the daily and monthly administration of tariffs related to the transportation of customer secured gas supplies.

In June 1993 I began work at Nevada Power Company where I held the positions of Fuels Analyst and Manger Gas & Oil Procurement. My primary responsibilities included the daily purchasing and scheduling of Nevada Power Company's natural gas fuel requirements, soliciting, negotiating, and contracting for gas supply and transportation resources for Nevada Power Company's natural gas and oil related fuel requirements; and, the administration of gas and oil supply and transportation contracts.

After leaving Nevada Power in November 1999, I entered law school. Starting in January 2002, I was employed by Ryan Marks Johnson & Todd, first as a law clerk where my responsibilities included drafting motions, oppositions, discovery requests and answers, researching legal issues, and drafting memorandum summarizing research and recommendations. After graduation and passing the Nevada Bar exam, I was promoted to Associate Attorney and my responsibilities included defending residential construction subcontractors in lawsuits involving construction defect claims.

In January 2005, I started at Morris Pickering & Peterson where I defended business entities in litigation concerning real estate escrow transactions, multifamily residential financing agreements, personal injury claims, products liability, and contract disputes.

In May 2007 I returned to work at Southwest Gas Corporation where I previously held the positions of Manager/Gas Purchases & Transportation and Senior Manager/Gas Purchases & Transportation. In February 2014, I was promoted to Director/Gas Supply. My responsibilities include soliciting, negotiating, and contracting for the gas supply and transportation resources required to meet the needs of the Southwest Gas Corporation's core customers. I am also responsible for nominations and confirmations of gas supplies on upstream interstate pipelines and the confirmation of all gas supplies at the delivery points into Southwest Gas Corporation's distribution system and the scheduling of those supplies to the Company's customers. Finally, I have responsibility for the support of the Gas Transaction System the Company utilizes to track gas purchases and bill transportation customers. I have testified before the Public Utilities Commission of Nevada and the California Public Utilities Commission.

Tab 5

Direct Testimony
of
Carla D. Ayala

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-19-0055

PREPARED DIRECT TESTIMONY

OF

CARLA AYALA

ON BEHALF OF

SOUTHWEST GAS CORPORATION

MAY 1, 2019

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of

CARLA AYALA

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
CARLA AYALA

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Carla Ayala. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Systems Planning department. My title is Senior Economist.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have prepared direct testimony before the Arizona Corporation Commission (Commission), the California Public Utilities Commission (CPUC) and the Public Utilities Commission of Nevada (PUCN).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor the Company's adjustments to the recorded test year bills and volumes, to derive the test period billing determinants.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The methodology used to develop test period billing determinants; and
- The Company's proposed adjustments to test year bills and volumes, including its proposed weather normalization adjustment.

II. METHODOLOGY USED TO DEVELOP BILLING DETERMINANTS

Q. 7 Please describe the methodology Southwest Gas utilized to develop the test period billing determinants.

A. 7 The development of the billing determinants commenced with the compilation of the monthly recorded number of bills and volumes by rate schedule for the test year – the 12 months ended January 31, 2019.

After compiling the recorded number of bills and volumes for the test year, Southwest Gas made the following adjustments to derive the adjusted test period billing determinants: (1) billing adjustments; (2) customer-specific volume annualizations; (3) customer reclassifications; (4) weather normalizations; and (5) customer annualizations. The details supporting these adjustments are set forth below and are shown in the Schedule H-2 Workpapers.

Q. 8 Why are adjustments made to the recorded test year number of bills and volumes?

A. 8 Adjustments are made to recorded bills and volumes to more accurately reflect the billing determinants that Southwest Gas would expect to experience during the rate effective period under normal weather conditions.

Q. 9 Has Southwest Gas made any changes to the general methodology for developing the billing determinants for the test period?

A. 9 No. In fact, Southwest Gas utilized the same general methodology to develop the billing determinants for its 2000 (Docket No. G-01551A-00-0309), 2004

(Docket No. G-01551A-04-0876), 2007 (Docket No. G-015551A-07-0504), 2010 (Docket No. G-01551A-10-0458) and 2016 (Docket No. G-015551A-16-0107) general rate cases in Arizona, and this methodology was approved in Decision Nos. 64172, 68487, 70665, 72723 and 76069 respectively.

<u>II. ADJUSTMENTS TO RECORDED NUMBER OF BILLS AND VOLUMES</u>

Q. 10 Please explain Southwest Gas' proposed billing adjustments.

A. 10 After compiling recorded test year billing determinants, significant billing anomalies are investigated to ensure that the correct consumption level is reflected for each month in the test year. A majority of the corrections for the billing adjustments involve restating the monthly consumption levels for customer bills to reflect actual monthly usage. These adjustments are typically adjustments between months and do not impact the total test year sales. This adjustment is necessary to ensure that the monthly adjusted volumes accurately reflect actual test year consumption. Otherwise, distorted monthly values would reduce the reliability of the regression analysis associated with the weather normalization adjustments.

Q. 11 Please explain Southwest Gas' proposed volume annualization adjustments.

A. 11 After completing the corrections for billing adjustments, customer-specific volume annualization adjustments are performed to reflect a full year of consumption for each active customer (excluding residential and small commercial customers) billed during January 2019. The process involves estimating additional consumption for months during the test year where a new customer was not on-line or was clearly in a start-up phase, as well as removing consumption attributable to specific customers who discontinued service during the test year.

Q. 12 Please explain Southwest Gas' proposed customer reclassification adjustments.

A. 12 Customer reclassification adjustments move customers and their associated consumption volumes between rate schedules. Reclassification adjustments are required when a customer changes rate schedules during the test year. For example, a general service customer whose consumption increases or decreases may qualify for a different rate schedule. These adjustments are performed to ensure that customer-specific consumption reflects a full 12-months of usage under the correct rate schedule at the end of the test year. Reclassification adjustments do not impact the overall number of bills or volumes for the test year.

Q. 13 Please explain Southwest Gas' proposed weather normalization adjustments.

A. 13 Weather normalization adjustments are made to address warmer or colder than normal weather during the test year and provide a more accurate depiction of test period volumes under normal (average) weather conditions. To the extent that weather for the test year deviates from normal weather conditions, heat-sensitive consumption per customer should be adjusted to represent monthly test year volumes under normal weather conditions.

For the test year in this case, actual billing cycle heating degree days were approximately 0.6 percent colder than normal in Tucson and approximately 4.7 percent colder than normal in Phoenix. As a result of these deviations from normal weather, adjustments to test period volumes were computed to reflect anticipated volumes under normal weather conditions.

Weather normalization adjustments were completed for the following rate schedules: G-5 Single Family Residential; G-6 Multi-Family Residential; G-10 Single Family Low Income Residential; G-11 Multi-Family Low Income Residential; G-15 Special Residential; G-20 Master-Metered Mobile Home Park; G-25 Master-Metered Apartments; G-25 Small Commercial; G-25 Transportation Eligible (TE) Large Commercial; and G-25 Transportation Eligible (TE) Armed Forces.

Q. 14 What heating degree day normal did Southwest Gas use to weather normalize the heat-sensitive volumes for the test period?

A. 14 Southwest Gas used a ten-year average (120 months ended January 2019) of heating degree days, to represent normal weather conditions for the test period.

Q. 15 Is the use of ten-year average heating degree days to weather normalize the heat-sensitive volumes consistent with Southwest Gas' prior practices for general rate cases in Arizona?

A. 15 Yes. Southwest Gas has consistently utilized ten-year average heating degree days to weather normalize test period volumes in every general rate case filed in Arizona since 1986 (see Docket Nos. U-1551-86-300, U-1551-86-301, U-1551-89-102, U-1551-89-103, U-1551-90-322, U-1551-92-253, U-1551-93-272, U-1551-96-596, G-01551A-00-0309, G-01551A-04-0876, G-015551A-07-0504, G-01551A-10-0458, G-015551A-16-0107 and Decision Nos. 60352, 64172, 68487, 70665, 72723 and 76069).

Q. 16 Please explain Southwest Gas' procedure for calculating the weather normalization adjustments.

A. 16 Southwest Gas conducts regression analysis to quantify the historical relationships between actual monthly consumption per customer and heating degree days for each heat-sensitive customer class. The monthly consumption per heating degree day factors (regression coefficients) quantified in the regression analysis are then applied to monthly heating degree day deviations from normal to quantify the corresponding adjustments to consumption per customer.

Q. 17 What was the impact of the weather normalization adjustments upon the test year volumes?

A. 17 The net result of the weather normalization adjustments was a decrease in test year volumes of 2,834,857.

Q. 18 Please explain Southwest Gas' proposed customer annualization adjustments.

A. 18 Customer annualization adjustments were computed for the following rate schedules: G-5 Single Family Residential; G-6 Multi-Family Residential; G-10 Single Family Low Income Residential; G-11 Multi-Family Low Income Residential; and G-25 Small, Medium, Large I, and Large II Small Commercial.

Q. 19 What method was used to develop the customer annualization adjustments?

A. 19 Southwest Gas utilized the same methodology adopted by the Commission in Southwest Gas' last five general rate cases (see Docket Nos. U-1551-96-596, G-01551A-00-0309, G-01551A-04-0876, G-015551A-07-0504, G-01551A-10-0458, G-015551A-16-0107 and Decision Nos. 60352, 64172, 68487, 70665, 72723 and 76069). This method captures the seasonal nature of test year customer growth by comparing the number of customers in the last month of the test year, January 2019, to the same month of the prior year, January 2018. The growth in customers is then prorated across the test year in declining intervals with 11/12ths of the adjustment in the first month of the test year (February 2019), 10/12ths in the second month (March 2019) and so forth. Adjustments to annualize volumes are made by multiplying the monthly customer additions by the respective monthly weather-adjusted average use per customer. Customer and volume adjustments are then added to the weather-normalized monthly bills and volumes to produce annualized test period monthly bills and volumes.

Q. 20 Why were the customer annualization adjustments only performed for the residential and small commercial customer classes?

A. 20 All rate schedules other than residential and small commercial, were annualized by individual customers, based upon customer-specific information. These customer-specific annualization adjustments are covered under the volume annualization adjustments discussed in Question and Answer 11. Because of the sheer magnitude of the number of customers in the residential and small commercial customer classes, which includes thousands of billing records, tracking each customer's billing history to perform customer-specific billing or annualization adjustments is impractical. Accordingly, customer annualization adjustments are performed using the outlined methodology for the residential and small commercial customer classes.

Q. 21 Please summarize the impact of the adjustments performed for the preparation of the annualized number of bills and volumes for the test period.

A. 21 The impacts of each of the adjustments upon the number of bills and volumes included in the test year are indicated by rate schedule in Schedule H-2, sheets 5-8. All the adjustments (billing adjustments, customer-specific volume annualizations, customer reclassifications, weather normalization and customer annualizations) were conducted to ensure the accuracy and propriety of the number of bills and volumes used to establish rates.

Q. 22 Does this conclude your prepared direct testimony?

A. 22 Yes.

SUMMARY OF QUALIFICATIONS
CARLA AYALA

I graduated from New Mexico State University, Las Cruces, New Mexico, with a Bachelor of Arts degree in Economics in 2003. In December 2004, I graduated from New Mexico State University, Las Cruces, New Mexico with a Master of Arts degree in Economics, with a specialization in Public Utility Regulation.

In 2005, I joined Southwest Gas Corporation as an Analyst in the Demand Planning Department. In December 2009, I was promoted to Analyst III/Demand Planning, in November 2013, I was promoted to Economist and in November 2018, I was promoted to Sr Economist. I am responsible for performing bill frequency analysis for general rate case filings. I am also responsible for the development of weather normalized billing determinants for rate cases, the development of short- and long-range demand forecasts for rate cases and systems planning, analysis and monitoring of the regional economy in each of Southwest Gas' rate jurisdictions and assorted load research activities.

Tab 6

Direct Testimony
of
Kristien M. Tary

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-19-0055

PREPARED DIRECT TESTIMONY
OF
KRISTIEN M. TARY

ON BEHALF OF
SOUTHWEST GAS CORPORATION

MAY 1, 2019

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Prepared Direct Testimony
of
KRISTIEN M. TARY

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
KRISTIEN M. TARY

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Kristien M. Tary. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Regulation and Energy Efficiency department. My title is Senior Analyst.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously provided testimony to the Public Utilities Commission of Nevada and the Arizona Corporation Commission (Commission).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor the Company's Class Cost of Service Study (CCOSS) reflected in Schedule G and the associated workpapers, the supporting H Schedules, certain portions of Schedules A, C and E as identified in the Table of Contents for Volume III of the Application, and the Company's rate design proposal, which includes the continuation of the Delivery Charge Adjustment (DCA). I also support the minimum system study provided as Exhibit No.__(KMT-1).

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The Company allocated its cost of service to the appropriate rate classes using its CCOSS;
- The Company utilized the same methodology that has been used in previous cases and accepted by the Commission and the parties;
- The Company proposes to allocate the costs of the new LNG Facility to customer classes on demand;
- In compliance with a recommendation in the last rate case, the Company performed a minimum system study to support the allocation of distribution mains; and
- The Company is not proposing any changes to rate design, including the basic service charge and the DCA mechanism.

II. PURPOSE OF A CLASS COST OF SERVICE STUDY (CCOSS)

Q. 7 What is the purpose of a CCOSS?

A. 7 The purpose of a CCOSS is to allocate the cost of service, or revenue requirement, to the appropriate customer rate classes and determine the resulting rate of return for each customer class included in the study. In this case, the results of the CCOSS are used as a guide in establishing proposed class revenues and developing proposed rates for each customer class. These topics are discussed more fully below in Section IV, Rate Design.

Q. 8 How is the Company's cost of service allocated to each customer class?

A. 8 Initially, the Company's system and operations are analyzed to determine cost causation factors. Once the causation factors are determined, each customer class is examined to determine their proportionate responsibility to each causation factor. Based on the proportionate responsibility of each customer class, allocation factors are developed to use in the allocation of the Company's costs. After each cost is allocated across customer classes, the allocated amounts are summed. The resulting allocation of costs can then be used to determine an allocation of revenue requirement to each customer class. The sum of the revenue requirement allocated to each customer class will equal the Company's total revenue requirement. The development of the CCOSS is described in more detail below.

Q. 9 Please describe the CCOSS schedules you are supporting.

A. 9 I sponsor the CCOSS Schedules G-1 through G-7. The CCOSS summarized in Schedule G-1 was performed using Southwest Gas' currently effective rates and rate schedules. Schedule G-2, Sheet 1 reflects, by customer class, the revenue and resulting rate of return requested in the Company's Application. Schedule G-2, Sheet 2 reflects the revenue and rate of return at Southwest Gas' proposed rates for each customer class. Schedules G-3 through G-7 support the allocation of costs summarized in Schedules G-1 and G-2.

III. DEVELOPMENT OF THE CCOSS

Q. 10 Please describe the process for developing the CCOSS.

A. 10 The Company utilizes a three-step process to develop the CCOSS, where costs are: 1) functionalized; 2) classified; and 3) allocated to the customer classes included in Southwest Gas' present and proposed rate design.

Q. 11 What is meant by cost functionalization?

A. 11 Cost functionalization is the assignment of plant investment costs and expenses to the appropriate operating functions. Southwest Gas' functionalization follows the Federal Energy Regulatory Commission (FERC) uniform system of accounts. The major functions are production, storage, transmission, and distribution. Since Southwest Gas currently has no production or transmission facilities in its Arizona service areas, all costs are appropriately functionalized as either storage or distribution.

Q. 12 What is meant by cost classification?

A. 12 Cost classification is the process of identifying whether Southwest Gas' plant investment costs and incurrence of expenses are related to: 1) providing capacity, i.e. sizing its facilities to serve customers' maximum demands; 2) the annual volume of gas actually delivered; or 3) providing customers with access, including related meter reading and billing expenses, to Southwest Gas' service irrespective of the amount of gas used. These are commonly referred to as demand, commodity and customer classifications, respectively.

Q. 13 What is meant by cost allocation?

A. 13 Cost allocation is the process of apportioning costs classified as demand, commodity or customer to each rate class based on distinct characteristics of class demand, class consumption and number of customers associated with each class. Demand-related allocations are based on relative customer class capacity demands. Commodity allocations are based on relative customer class annual natural gas consumption. Customer allocations are related to the number of customers in each class. A weighted customer class allocator is also developed to recognize cost variations in providing service, such as meter and service cost and billing expenses.

Q. 14 Is this the same process Southwest Gas has utilized in prior Arizona general rate cases?

A. 14 Yes. The Company has utilized, and the Commission has accepted, this methodology for performing the CCOSS in the Company's past several rate cases.

Q. 15 Are there any new functionalization costs in the CCOSS for the instant Application, compared to the CCOSS in the Company's last Arizona general rate case?

A. 15 Yes. In this case, Southwest Gas included costs related to the Liquefied Natural Gas (LNG) storage facility as a proforma adjustment. The prepared direct testimony of Randi L. Cunningham discusses the LNG storage facility and related operations and maintenance expenses. For purposes of the CCOSS, the Company allocated the cost of the LNG storage facility to customer classes on demand.

Q. 16 Why did Southwest Gas prepare a minimum system study?

A. 16 The Commission's decision in the Company's last general rate case (Decision No. 76069 in Docket No. G-01551A-16-0107) requires that the Company provide a minimum system study as a compliance item in this proceeding, to support the allocation of distribution mains in the CCOSS.

Q. 17 What is a minimum system study?

A. 17 A minimum system study determines the customer-related portion of the Company's distribution mains. The study identifies the cost necessary to provide customers access to the Company's distribution system under minimum or zero load conditions. The resulting cost determines the percentage of distribution mains expense needed to provide customers access to the system and is considered customer-related. The remaining distribution mains expense is needed to serve customers' peak demand for natural gas, which is considered demand-related. The Company's minimum system study is attached to my testimony as Exhibit No. ___(KMT-1).

IV. RATE DESIGN

Q. 18 What considerations guided Southwest Gas' proposed rate design?

A. 18 The Company focused on the following key objectives in its rate design proposal presented in this Application: 1) the fair and equitable recovery of costs; 2) rates that work well in concert with the DCA; 3) customer acceptance and understandability; and 4) the effect of the rate design on the promotion of the Company's energy efficiency and conservation efforts.

Q. 19 Please explain how the concepts of fairness and equality affected Southwest Gas' rate design decisions.

A 19 Nearly 100 percent of Southwest Gas' cost of providing service is fixed and does not increase or decrease with changes in customers' annual consumption. These fixed costs are classified as customer and demand-related. Customer costs are incurred as a result of connecting a customer to the distribution system and are relatively equal for all residential customers. Demand costs are determined by how much gas customers need during the peak demands on the distribution system. When customer and demand-related fixed costs are recovered through variable charges, Southwest Gas will not recover the full cost of providing service from its low-use customers, while recovering more than it costs to provide service from its high-use customers. If this shift of cost responsibility amongst similarly situated customers becomes too great, the fairness and equality of the rate design come into question. A true cost-based rate design would recover the entire customer and demand costs in monthly fixed charges. However, Southwest Gas' proposed rate design balances cost of service rate principles with the recognition of past Commission policy and decisions requiring that a certain portion of the fixed cost of service be collected in the variable charge.

Q. 20 Is the Company proposing an increase to monthly basic service charges as part of its rate design proposal?

A. 20 No. Southwest Gas' currently effective basic service charges continue to accomplish the balancing principles discussed above and the Company is not proposing to increase the basic service charge associated with any rate schedule as part of its proposed rate design.

Q. 21 How does Southwest Gas' proposed rate design accomplish the objective of working in tandem with the DCA?

A. 21 Cost-based rates recognize the difference between fixed and variable costs associated with providing service and assign the costs to fixed and variable rate components accordingly. Under a cost-based rate design, fixed charge rates recover the fixed costs, and variable rates recover the variable costs. However, for various reasons, gas distribution rate design may deviate from cost-based factors, with some portion of the fixed cost of service being recovered through volumetric rates. The greater this deviation from cost-based rates, the greater the potential that actual cost recovery will vary from the authorized cost of service.

Although Southwest Gas' proposed rates do not recover all fixed costs in fixed monthly charges, the Company's proposed rate design works in tandem with the DCA by recovering a reasonable portion of fixed costs through fixed charges, which mitigates the deferrals associated with the DCA.

Q. 22 How does Southwest Gas' rate design achieve the objective of customer acceptance and understandability?

A. 22 Southwest Gas is proposing to retain the existing monthly basic service charges and existing rate structures of its current rate design, and simply adjust the commodity rates to recover the proposed class revenues. The Company's Arizona customers have had many years of experience with the current rate design, as it has been in place since the Company's 2007 general rate case.

Q. 23 Does the Company's proposed Rate Design contemplate the continuation of its DCA provision?

A. 23 Yes. The DCA provision has performed as designed and ensured that the Company has recovered no more or less than its Commission-authorized margin.

Q. 24 Are there benefits to the Company's DCA mechanism?

A. 24 Yes. The DCA mechanism provides benefits to both the Company and its customers. The DCA contributes to revenue stability for the Company, which encourages improvements in financial metrics putting downward pressure on the Company's overall cost of service to ultimately benefit customers. In addition, the DCA provides Southwest Gas greater flexibility in rate design. As discussed above, with the DCA, Southwest Gas is able to retain its existing monthly basic service charges. This allows the Company to propose rates that send stronger price signals to customers to use natural gas as efficiently as possible, and minimizes the impact, particularly to smaller residential and commercial customers of increasing basic service charges as a means of increasing revenue stability in lieu of the DCA.

Q. 25 Is the Company proposing any modifications to the DCA or to how the monthly margin per customer amounts are calculated?

A. 25 No. The Company recommends the Commission authorize the continuation of the DCA provision and that the Monthly Margin per Customer amounts be calculated as agreed upon with Commission Staff in the last general rate case by distributing the increase in annual margin per customer equally during 12 months.

Q. 26 Does this conclude your prepared direct testimony?

A. 26 Yes.

SUMMARY OF QUALIFICATIONS
KRISTIEN M. TARY

I hold a Bachelor of Arts degree in Communication Studies from the University of Nevada, Las Vegas.

In 2000, I began my career at Southwest Gas Corporation (Southwest Gas or Company) as an Intern in the Corporate Communications Department. In 2001, I was hired by the Company as a Professional Staff Entry in the Corporate Communications Department. In 2004, I was promoted to Communications Representative. From 2001 to 2009, my primary responsibilities included representing the Company both internally and externally regarding communications, media relations, and consumer and community affairs; providing communications support for low-income programs and regulatory/compliance items; providing expertise and resources to create and execute strategic communications plans.

In 2009, I was promoted to Analyst II in the State Regulatory Affairs Department. In this position, my primary responsibilities included management and monitoring of regulatory proceedings in Arizona, California and Nevada, as well as ensuring the Company met its regulatory compliance obligations. In this role, I also facilitated and managed the data request process, provided regulatory perspective when responding to customer inquiries, and acted as a liaison with the state regulatory agencies and consumer advocates, when appropriate. In addition, I collaborated with regulatory representatives from other utilities regarding statewide initiatives and assisted with legislative activities.

In October 2014, I transitioned to the Analyst II position in the Regulation and Energy Efficiency Department; then, in March 2017, I was promoted to Senior Analyst within the same department. In my current position, I am responsible for calculating and implementing customer rates; overseeing tariff administration; formulating rate design recommendations; analyzing regulatory decisions and impacts; conducting economic feasibility analysis for customer bypass; handling various rate and revenue requirement analyses; as well as preparing forecasted results of operations and developing recommendations to management in support of corporate financial and regulatory goals for the Company's Arizona, California and Nevada ratemaking jurisdictions. In addition, I develop and maintain complex and technical analyses of multiple components for the Company's cost of service and rate design allocation models. I have testified in proceedings before the Arizona Corporation Commission and the Public Utilities Commission of Nevada.

Southwest Gas Corporation
Pipe Quantity and Amount
Total Arizona
For the Calendar Years 2011 through 2018
Data as of January 31, 2019

Property Unit Number	Property Unit Description	Vintage Year	Quantity	Amount	Unit Cost
		MAINS			
3760101	Main, (Under 2") Pe	2014	212,268	6,356,850.00	29.95
3760102	Main, 2" Pe Plastic	2014	1,137,833	41,080,328.00	36.10
3760103	Main, 3" Pe Plastic	2014	3	22.00	7.33
3760104	Main, 4" Pe Plastic	2014	372,582	34,911,228.00	93.70
3760106	Main, 6" Pe Plastic	2014	18,595	972,126.00	52.28
3760201	Main, (Under 2") Steel	2014	303	42,651.00	140.76
3760202	Main, 2" Steel	2014	4,563	2,504,394.00	548.85
3760203	Main, 3" Steel	2014	12	11,758.00	979.83
3760204	Main, 4" Steel	2014	22,108	4,531,291.00	204.96
3760206	Main, 6" Steel	2014	39,658	7,607,442.00	191.83
3760208	Main, 8" Steel	2014	57,773	12,688,448.00	219.63
3760210	Main, 10" Steel	2014	387	348,044.00	899.34
3760212	Main, 12" Steel	2014	33,386	9,027,922.00	270.41
3760216	Main, 16" Steel	2014	2,777	988,749.00	356.05
Total Mains for 2014			1,902,248	121,071,253	63.65
3760101	Main, (Under 2") Pe	2015	155,639	5,189,520.00	33.34
3760102	Main, 2" Pe Plastic	2015	1,119,740	43,947,526.00	39.25
3760103	Main, 3" Pe Plastic	2015	2	4,811.00	2,405.50
3760104	Main, 4" Pe Plastic	2015	411,921	39,206,209.00	95.18
3760106	Main, 6" Pe Plastic	2015	20,169	447,099.00	22.17
3760201	Main, (Under 2") Steel	2015	251	24,592.00	97.98
3760202	Main, 2" Steel	2015	2,628	1,707,513.00	649.74
3760203	Main, 3" Steel	2015	28	10,850.00	387.50
3760204	Main, 4" Steel	2015	11,569	2,876,275.00	248.62
3760206	Main, 6" Steel	2015	21,342	4,777,546.00	223.86
3760208	Main, 8" Steel	2015	44,554	10,382,349.00	233.03
3760210	Main, 10" Steel	2015	137	307,446.00	2,244.13
3760212	Main, 12" Steel	2015	41,295	17,413,913.00	421.70
3760216	Main, 16" Steel	2015	869	271,114.00	311.98
3760401	Main, (Under 2")ABS Plastic	2015	1	10.00	10.00
Total Mains for 2015			1,830,145	126,566,773	69.16

3760101	Main, (Under 2") Pe	2016	97,568	4,649,470.00	47.65
3760102	Main, 2" Pe Plastic	2016	925,826	46,246,423.00	49.95
3760103	Main, 3" Pe Plastic	2016	7	1,652.00	236.00
3760104	Main, 4" Pe Plastic	2016	273,962	24,338,566.00	88.84
3760106	Main, 6" Pe Plastic	2016	14,940	1,316,917.00	88.15
3760201	Main, (Under 2") Steel	2016	286	472,699.00	1,652.79
3760202	Main, 2" Steel	2016	3,081	1,976,648.00	641.56
3760203	Main, 3" Steel	2016	7	2,360.00	337.14
3760204	Main, 4" Steel	2016	11,781	2,535,418.00	215.21
3760206	Main, 6" Steel	2016	17,901	2,762,983.00	154.35
3760208	Main, 8" Steel	2016	16,911	5,260,309.00	311.06
3760210	Main, 10" Steel	2016	36	328,661.00	9,129.47
3760212	Main, 12" Steel	2016	5,554	3,209,813.00	577.93
3760602	Main, 2" PVC Plastic	2016	23	238.00	10.35
Total Mains for 2016			1,367,883	93,102,157	68
3760101	Main, (Under 2") Pe	2017	26,503	4,556,342.00	171.92
3760102	Main, 2" Pe Plastic	2017	1,115,715	51,997,429.00	46.60
3760103	Main, 3" Pe Plastic	2017	3	419.00	139.67
3760104	Main, 4" Pe Plastic	2017	238,451	21,335,072.00	89.47
3760106	Main, 6" Pe Plastic	2017	28,951	2,160,211.00	74.62
3760201	Main, (Under 2") Steel	2017	79	186,733.00	2,363.71
3760202	Main, 2" Steel	2017	1,873	3,175,739.00	1,695.54
3760203	Main, 3" Steel	2017	11	2,475.00	225.00
3760204	Main, 4" Steel	2017	8,527	2,747,695.00	322.23
3760206	Main, 6" Steel	2017	20,847	5,968,683.00	286.31
3760208	Main, 8" Steel	2017	21,953	6,110,153.00	278.33
3760210	Main, 10" Steel	2017	2,494	2,265,890.00	908.54
3760212	Main, 12" Steel	2017	41,187	16,443,249.00	399.23
3760216	Main, 16" Steel	2017	32	532,439.00	16,638.72
Total Mains for 2017			1,506,626	117,482,529	78
3760101	Main, (Under 2") Pe	2018	4,230	1,554,910.00	367.59
3760102	Main, 2" Pe Plastic	2018	592,279	22,763,806.00	38.43
3760104	Main, 4" Pe Plastic	2018	102,785	6,562,868.00	63.85
3760106	Main, 6" Pe Plastic	2018	10,270	663,185.00	64.57
3760201	Main, (Under 2") Steel	2018	246	1,040,742.00	4,230.66
3760202	Main, 2" Steel	2018	1,604	2,333,609.00	1,454.87
3760204	Main, 4" Steel	2018	6,699	1,476,226.00	220.37
3760206	Main, 6" Steel	2018	3,998	1,283,754.00	321.10
3760208	Main, 8" Steel	2018	15,513	5,486,811.00	353.69
3760210	Main, 10" Steel	2018	569	2,641,095.00	4,641.64
3760216	Main, 16" Steel	2018	4	43,907.00	10,976.75
3760602	Main, 2" PVC Plastic	2018	43	1,431.00	33.28
Total Mains for 2018			738,240	45,852,344	62

Five Year Total (2014 - 2018)			
3760101 Main, (Under 2") Pe	496,208	22,307,092	44.96
3760102 Main, 2" Pe Plastic	4,891,393	206,035,512	42.12
3760103 Main, 3" Pe Plastic	15	6,904	460.27
3760104 Main, 4" Pe Plastic	1,399,701	126,353,943	90.27
3760106 Main, 6" Pe Plastic	92,925	5,559,538	59.83
3760201 Main, (Under 2") Steel	1,165	1,767,417	1,517.10
3760202 Main, 2" Steel	13,749	11,697,903	850.82
3760203 Main, 3" Steel	58	27,443	473.16
3760204 Main, 4" Steel	60,684	14,166,905	233.45
3760206 Main, 6" Steel	103,746	22,400,408	215.92
3760208 Main, 8" Steel	156,704	39,928,070	254.80
3760210 Main, 10" Steel	3,623	5,891,136	1,626.04
3760212 Main, 12" Steel	121,422	46,094,897	379.63
3760216 Main, 16" Steel	3,682	1,836,209	498.70
3760602 Main, 2" PVC Plastic	66	1,669	25.29
3760401 Main, (Under 2")ABS Plastic	1	10	10.00
	7,345,142	504,075,056	6,782
2" and <2" Mains	7,345,142	311,287,118	42.38
--"Less Material Cost 2"	7,345,142	7,005,062	0.95
		304,282,056	

Customer-Related Percentage of Distribution Mains	60.36%

Three Year Total (2016 - 2018)			
3760101 Main, (Under 2") Pe	128,301	10,760,722	83.87
3760102 Main, 2" Pe Plastic	2,633,820	121,007,658	45.94
3760103 Main, 3" Pe Plastic	10	2,071	207.10
3760104 Main, 4" Pe Plastic	615,198	52,236,506	84.91
3760106 Main, 6" Pe Plastic	54,161	4,140,313	76.44
3760201 Main, (Under 2") Steel	611	1,700,174	2,782.61
3760202 Main, 2" Steel	6,558	7,485,996	1,141.51
3760203 Main, 3" Steel	18	4,835	268.61
3760204 Main, 4" Steel	27,007	6,759,339	250.28
3760206 Main, 6" Steel	42,746	10,015,420	234.30
3760208 Main, 8" Steel	54,377	16,857,273	310.01
3760210 Main, 10" Steel	3,099	5,235,646	1,689.46
3760212 Main, 12" Steel	46,741	19,653,062	420.47
3760216 Main, 16" Steel	36	576,346	16,009.61
3760602 Main, 2" PVC Plastic	66	1,669	25.29
	3,612,749	256,437,030	23,630
2" and <2" Mains	3,612,749	172,364,255	47.71
--"Less Material Cost 2"	3,612,749	3,445,479	0.95
		168,918,776	

Customer-Related Percentage of Distribution Mains	65.87%

Tab 7

Direct Testimony
of
Dane A. Watson

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO.: G-01551A-19-0055

PREPARED DIRECT TESTIMONY
OF
DANE A. WATSON, PE CDP, PARTNER
ALLIANCE CONSULTING GROUP

ON BEHALF OF
SOUTHWEST GAS CORPORATION

Filed: May 1, 2019

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Prepared Direct Testimony
of
DANE A. WATSON

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
Dane A. Watson

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Dane A. Watson, and my business address is 101 E. Park Blvd., Suite 220, and Plano, Texas 75074.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am a Partner of Alliance Consulting Group (Alliance). Alliance provides consulting and expert services to the utility industry

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 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. My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Are you certified as a depreciation expert?

A. 4 Yes. The Society of Depreciation Professionals (the Society) has established national standards for depreciation professionals. The Society administers an examination and has certain required qualifications to become certified in this field. I have met all requirements and have been recognized as a Certified Depreciation Professional (CDP).

Q. 5 Please outline your experience in the field of depreciation.

A. 5 Since graduation from college in 1985, I have worked in the area of depreciation and valuation. I founded Alliance in 2004 and am responsible for conducting depreciation, valuation and certain accounting-related studies for utilities in various industries. My duties relate to preparing depreciation studies and include (1) assembling and analyzing historical and simulated data, (2) conducting field reviews, (3) determining service life and net salvage estimates, (4) calculating annual depreciation, (5) presenting recommended depreciation rates to utility management for its consideration, and (6) supporting such rates before regulatory bodies.

My prior employment from 1985 to 2004 was with Texas Utilities (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 (PE) in the State of Texas and, as previously noted, have meet the requirements for the Certified Depreciation Professional. I am a Senior Member of the Institute of Electrical and Electronics Engineers (IEEE) and have held numerous offices on the Executive Board of the Dallas Section, Region and World-wide offices of IEEE. I have served as President of the Society of

Depreciation Professionals twice, most recently in 2015.

Q. 6 Have you previously testified before any regulatory commissions?

A. 6 Yes. I have appeared before numerous state and federal agencies in my 34-year career in performing depreciation studies. I have conducted more than 200 depreciation studies, and filed written testimony and/or testified before 35 regulatory commissions. My Statement of Qualifications, along with a complete listing of my testimony appearances is found Appendix A to this testimony

Q. 7 Have you previously testified before the Arizona corporation commission?

A. 7 Yes. I appeared before this Commission in Docket No. G-01551A-16-0107 when I sponsored the most recent depreciation study for Southwest Gas.

II. PURPOSE OF DIRECT TESTIMONY

Q. 8 What is the purpose of your direct testimony in this proceeding?

A. 8 I sponsor the removal cost allocation study conducted in compliance with Decision No. 76069 in Docket No. G-01551A-16-0107. The study is provided as Exhibit No.___(DAW-1).

Q. 9 Do you have experience conducting removal cost allocation studies?

A. 9 Yes. I have conducted removal cost allocation studies for natural gas companies across the United States. In two separate cases before the Arkansas Public Service Commission, I performed removal cost studies for CenterPoint Arkansas in Dockets 06-161-U and 15-098-U. For Atmos Energy, I have performed removal cost allocation studies for the following jurisdictions: Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee, Texas and Virginia.

Q. 10 Are you sponsoring any exhibits in this proceeding?

A. 10 Yes. I sponsor the following exhibits, which were prepared by me, or under my direct supervision:

- DAW-1 – Southwest Gas – Arizona Removal Cost Allocation Study

Q. 11 Please summarize your prepared direct testimony in this proceeding.

A. 11 My testimony discusses the removal cost study conducted for purposes of this proceeding, including the two factors that contributed to the high removal costs reflected in the last depreciation study for Accounts 376 and 380. Based upon the results of the study, I conclude that the Company's removal cost process follows industry best practice, and no adjustment to the Company's accounting records for removal costs in Accounts 376 and 380 are necessary. All charges accurately reflect net salvage experience for Southwest Gas.

III. SOUTHWEST GAS - ARIZONA REMOVAL COST ALLOCATION STUDY

Q. 12 Please describe the origin of the compliance item that your testimony addresses.

A. 12 As mentioned above, I conducted the depreciation study presented by Southwest Gas in Docket No. G-01551-A-16-0107. The data used in that study reflected the most recent experience and future expectations for life and net salvage characteristics for assets in Southwest Gas' Arizona rate jurisdiction as of December 31, 2015. Because the study showed removal costs for Accounts 376 and 380 that were higher in 2015 than in previous periods, Southwest Gas agreed to present a removal cost study in its next general rate case that analyzed the amounts of removal cost being booked in the accumulated provision for depreciaiton for mains and services in each account. More specifically, the settlement agreement approved by the Commission states:

> In conjunction with the Company's next general rate case filing, SWG will perform a detailed and objective cost of removal study to determine the validity of significant increases in cost of removal charges recorded in 2015, and for any that may occur after 2015 and before the next rate case. In the meantime, the Company shall review the cost of removal charges recorded in mains and services accumulated depreciation accounts in 2015 to determine whether charges, if any, should be transferred to operations, maintenance, or other accounts. This review would help ensure the account balances of mains and services accumulated depreciation are fairly stated going forward into the next rate case. SWG shall provide the results of such study and review as part of its next general rate case filing.

Q. 13 Do you have an initial observation about Southwest Gas' Arizona removal costs for accounts 376 and 380?

A. 13 Yes. As referenced above, the removal costs for these accounts were much larger in 2015 than in previous periods. The tables below show the results presented in the depreciation study.

Table 1 - Removal Cost Account 376

Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %
2006	2,378,319	0	512,089	-512,089	-21.53%
2007	3,464,438	0	778,505	-778,505	-22.47%
2008	4,705,622	0	889,561	-889,561	-18.90%
2009	7,425,368	0	1,297,824	-1,297,824	-17.48%
2010	7,057,129	24,439	1,522,992	-1,498,553	-21.23%
2011	5,667,833	0	1,220,613	-1,220,613	-21.54%
2012	5,255,656	0	1,743,686	-1,743,686	-33.18%
2013	5,284,475	0	2,742,020	-2,742,020	-51.89%
2014	5,471,831	0	1,858,030	-1,858,030	-33.96%
2015	1,385,718	0	5,230,681	-5,230,681	-377.47%
Total	48,096,389	24,439	17,796,000	-17,771,561	-36.95%

Table 2 - Removal Cost Account 380

Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %
2006	4,041,947	0	1,383,267	-1,383,267	-34.22%
2007	3,990,321	0	1,780,272	-1,780,272	-44.61%
2008	3,035,470	0	1,834,578	-1,834,578	-60.44%
2009	4,733,764	0	1,729,355	-1,729,355	-36.53%
2010	4,074,380	0	1,639,128	-1,639,128	-40.23%
2011	6,173,739	0	1,540,264	-1,540,264	-24.95%
2012	5,083,477	0	1,653,716	-1,653,716	-32.53%
2013	3,398,449	0	2,269,607	-2,269,607	-66.78%
2014	4,340,904	0	2,987,831	-2,987,831	-68.83%
2015	10,178,924	0	27,095,366	-27,095,366	-266.19%
Total	49,051,375	0	43,913,385	-43,913,385	-89.53%

Q. 14 What net salvage parameters were recommended in the company's last depreciation study?

A. 14 Alliance's net salvage recommendations in the last study excluded the effect of the 2015 increase in the net salvage percentage. Alliance recommended negative 35 and negative 55 percent for Accounts 376 and

380, respectively. The Commission ultimately adopted negative 30, and negative 55 percent for Accounts 376 and 380, respectively.

Q. 15 As part of the cost removal study did you review how the company allocates removal costs for its assets?

A. 15 Yes. The Company uses a compatible units (CU) system for pipe, regulators, and other types of plant. In Alliance's experience, CU systems are used throughout the utility industry and are the predominant method of determining removal cost. Tasks are specified in the system with installation and removal units. The computer software includes labor CUs, and the designer of each project estimated how many hours are necessary to complete the activity as well as which CU's are part of that task. For example, there is a CU called 3-man crew, where the contractor sends a 3-person crew who may have a backhoe or other heavy equipment needed to complete the job. The workers may have to dig 3 bell holes to abandon a main or service.

The Company's estimating and construction management system uses a fixed cost per foot to abandon pipeline facilities that is computed from a competitively bid and awarded pricing structure for the contract amounts the contractors used for every project. A Master Pipeline contract is used for routine capital work for new pipeline installations, relocations and replacements which has specific line items for each activity (including removal activities). The Company loads master contract line items into the Field Operations Management System (FOMS) where the project estimated (including removal estimates are created). Large, high-dollar projects are separately bid, and the design estimates are also generated in FOMS, however the contractor's bid costs are maintained in the Voucher section of the FOMS application. The invoice goes into PowerPlan which is the continuing property records system and is integrated to function with FOMS project estimates.

Q. 16 How are these charges booked to accumulated depreciation?

A. 16 The Company's operational and accounting practices correspond with those used by numerous utilities across the nation. The Company uses PowerPlan for its fixed asset system. It is a software system used by the majority of utility companies across the United States and Canada. The FOMS system interfaces with PowerPlan to allocate charges between construction and removal cost and subsequently record to the accumulated provision for depreciation. The PowerPlan system has been in place since 2008 and no major modifications have occurred during that time.

The Company nearly always abandons pipe in place, and only removes a main or service if it is in direct conflict with other newly installed facilities - typically facilities installed and owned by municipalities or governmental agencies. If the asset is physically removed from the ground, the removal cost is very high (likely higher than the installation of the new pipe). Physical removal would also require the Company to replace paving and treat wrap asbestos. Since this is an infrequent activity, the increase in removal costs would is not attributable to removing pipe from the ground.

Q. 17 Based on your review, do you recommend any changes to Southwest Gas' accounting practices as they relate to the allocation of removal costs and the booking of such charges to accumulated depreciation?

A. 17 No. Southwest Gas' account balances for mains and services accumulated depreciation are fairly stated. In addition, the Company's accounting practices follow best practices used by gas utilities across the United States.

Q. 18 Did your removal study identify the factors that contributed to the increased removal costs in accounts 376 and 380?

A. 18 Yes. After review of the Company's removal cost results, the significant increases in removal cost were due to pro-active retirement projects for mains and services in the 2015-2018 timeframe and the inadvertent absence of the retirements reclassified from 2015. The charges that were made to accumulated depreciation are correct and no adjustment should be made to the Company's plant accounting system for the subject accounts.

Q. 19 Please describe the proactive mains and services retirements that impacted the removal costs.

A. 19 Beginning in 2014-2015, there was a significantly higher level of retirement activity than in the past. That retirement activity impacted retirement and net salvage results in 2015 and in periods thereafter. A significant proactive safety initiative took place in that timeframe. The M7000/M8000 PE Inactive Services and Stub Abandonment Project (ISSAP) started in 2015. ISSAP is a Company initiative to abandon or replace the M7000/M8000 pipe. At the beginning of 2015 (or late 2014), removal-only blankets were created (RB01600 - Mains and RB02600 - Services) and used to track the retirements and removal cost for pipe that was being abandoned (i.e. not replaced). Most of the activity was on services in the early periods; however, there was some activity in mains. Service and main stubs and no/low use services were identified and abandoned. In 2017, the activity began to increase for mains. In Arizona, this project was competitively bid and there was one contractor generally dedicated to the work.

Q. 20 What is the significance of the removal-only blanket work orders as they relate to the reported removal costs?

A. 20 Removal-only projects incur a higher removal cost and removal cost percentage since there is no construction activities to allocate what would otherwise be common cost. Since both blanket projects are retirement only, all charges go to removal cost, with nothing being booked to a new installation. This increases removal cost in these accounts over the duration of the projects.

Q. 21 What charges did the two removal-only blanket projects produce?

A. 21 The activity for mains retirements is shown below.

Table 3 - Blanket Project for Mains
Account 376 RB016000

Year	Retirements	Removal Costs	COR %
2015	172,523	1,349,683	782%
2016	276,209	2,605,085	943%
2017	156,101	1,151,625	738%
2018	14,324	150,867	1053%
Total	619,157	5,257,260	849%

The activity for services retirements is shown below:

Table 4 - Blanket Project for Services
Account 380 RB026000

Year	Retirements	Removal Costs	COR %
2015	4,807,080	23,731,616	494%
2016	7,491,370	18,866,309	252%
2017	4,659,902	10,453,448	224%
2018	2,353,338	3,228,643	137%
Total	19,311,690	56,280,016	291%

Q. 22 Please describe how the inadvertent exclusion of retirement data contributed to the reported removal costs.

A. 22 In examining data provided by Southwest Gas, Alliance determined that the depreciation study provided in the last general rate case did not capture the appropriate level of retirements. This was an inadvertent oversight that occurred when Southwest Gas provided 2015 transactional data. The transaction year 2015 was adjusted and did not include retirement activity that physically occurred in prior years but was being unitized (reflected on the books) in 2015. The Company resets the vintage of the various retirement transactions to the year that the retirements actually occurred. As a result, the 2015 retirements were understated in the depreciation study. At the same time, the removal cost charges were not adjusted on the Company's books into prior years so the full level of removal cost related to the retirements that were restated into previous years were still included in the 2015 data. This inconsistency resulted in the retirements used in the net salvage analysis being too low (or alternatively, removal cost was too high based on the retirements reflected in 2015). Thus, net salvage percentages in 2015 appear much higher than they were in reality.

Q. 23 What is the impact of correcting the retirements and removing the blanket retirement projects from company history?

A. 23 After adjusting the retirements and removing the blanket projects, the net salvage analysis for the accounts is as follows:

Table 5 Net Salvage History
Account 376 Adjusted

Year	Remove Blanket Project Activity Retirements	Remove Blanket Project Activity Removal Costs	COR %
2011	5,667,833	1,220,613	22%
2012	5,255,656	1,743,686	33%
2013	5,284,475	2,742,020	52%
2014	5,471,831	1,858,030	34%
2015	10,203,931	3,880,998	38%
2016	9,333,391	2,245,829	24%
2017	8,422,674	2,214,141	26%
2018	15,440,109	5,434,944	35%
Total	65,079,900	21,340,261	33%

Table 6 Net Salvage History
Account 380 Adjusted

Year	Retirements	Removal Costs	COR %
2011	6,173,739	1,540,264	25%
2012	5,083,477	1,653,716	33%
2013	3,398,449	2,269,607	67%
2014	4,340,904	2,987,831	69%
2015	5,481,660	3,363,750	61%
2016	5,259,246	3,305,103	63%
2017	7,422,484	3,553,934	48%
2018	7,951,201	4,124,944	52%
Total	45,111,160	22,799,149	51%

As can be seen above, the net salvage results return to levels that had been experienced in prior periods. Small fluctuations in removal cost can still occur since retirements and removal costs may not be synchronized (i.e. removal cost activity occurring in different transaction years than the processing of retirements).

Q. 24 What do you conclude after reviewing the company's processes and data?

A. 24 Overall, the net salvage results are consistent with the Company's history and variations seen in 2015 are appropriate and accurate. The Company's removal cost process follows industry best practice. No adjustment to the Company's accounting records for removal cost in Accounts 376 and 380 is necessary. All charges accurately reflect net salvage experience for Southwest Gas.

IV. CONCLUSION

Q. 25 What do you recommend regarding the removal cost study?

A. 25 I recommend that the Commission accept this removal cost study and its results as full compliance with the requirements of the Decision No. in Docket No. G-01551A-16-0107. Further, as discussed above, it is my opinion that the charges made to accumulated depreciation are correct and that the account balances for mains and services accumulated depreciation are fairly stated. In addition, the Company's accounting practices follow best practices used by gas utilities across the United States. I therefore recommend that no adjustments be made to the Company's plant accounting system for Accounts 376 and 380.

Q. 26 Does this conclude your prepared direct testimony?

A. 26 Yes.

Statement of Qualifications

Dane A. Watson

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.

The Society of Depreciation Professionals ("the Society") has established national standards for depreciation professionals. The Society administers an examination and has certain required qualifications to become certified in this field. I met all requirements and have become a Certified Depreciation Professional ("CDP").

I have been a member of the Society of Depreciation Professionals Training Faculty since 2005. I developed and teach the capstone class, "Preparing and Defending a Depreciation Study" and "Engineering Aspects of a Depreciation Study". I also teach depreciation to participants from the American Gas Association and Edison Electric Institute and for the Michigan State University Regulatory Conference. I have also provided training to state commissions at the request of various regulatory bodies.

Since graduation 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 utilities in various industries. My duties relate 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 ("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 ("PE") in the State of Texas and a Certified Depreciation Professional. I am a Senior Member of the Institute of Electrical and Electronics Engineers (IEEE) and have held numerous offices on the Executive Board of the Dallas Section, Region and World-wide offices of IEEE. I currently serve as Treasurer of the Member and Geographic Unit Business Unit and serve on the IEEE Finance Committee. I have served as President of the Society of Depreciation Professionals twice, most recently in 2015.

Over the course of my career, I have testified in more than 180 proceedings before 35 regulatory bodies, both state commissions and FERC. A list of my testimony appearances before various regulatory bodies is provided below.

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos Kentucky	2018	Gas 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

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Depreciation Rates
Texas	Public Utility Commission of Texas	48371	Entergy Texas	2018	Electric Depreciation Study
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study
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
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
Texas	Railroad Commission of Texas	10669	CenterPoint South Texas	2017	Gas 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
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

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
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
Mississippi	Mississippi Public Service Commission	2017-UN-041	Atmos Energy	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	46957	Oncor Electric Delivery	2017	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD 201700078	CenterPoint Oklahoma	2017	Gas Depreciation Study
New York	FERC	ER17-1010-000	New York Power Authority	2017	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10580	Atmos Pipeline Texas	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10567	CenterPoint Texas	2016	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
North Carolina	North Carolina Utilities Commission	Docket G-9 Sub 77H	Piedmont Natural Gas	2016	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18195	Consumers Energy/DTE Electric	2016	Ludington Pumped Storage Depreciation Study
Alabama	FERC	ER16-2313-000	SEGCO	2016	Electric Depreciation Study
Alabama	FERC	ER16-2312-000	Alabama Power Company	2016	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-18127	Consumers Energy	2016	Natural Gas Depreciation Study
Mississippi	Mississippi Public Service Commission	2016 UN 267	Willmut Natural Gas	2016	Natural Gas Depreciation Study
Iowa	Iowa Utilities Board	RPU-2016-0003	Liberty-Iowa	2016	Natural Gas Depreciation Study
Illinois	Illinois Commerce Commission	GRM #16-208	Liberty-Illinois	2016	Natural Gas Depreciation Study
Kentucky	FERC	RP16-097-000	KOT	2016	Natural Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-16-067	Alaska Electric Light and Power	2016	Generating Unit Depreciation Study
Florida	Florida Public Service Commission	160170-EI	Gulf Power	2016	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
California	California Public Utilities Commission	A 16-07-002	California American Water	2016	Water and Waste Water Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-16-0107	Southwest Gas	2016	Gas Depreciation Study
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service Company of Colorado	2016	Electric Depreciation Study
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study
Hawaii	NA	NA	Hawaii American Water	2015	Water/Wastewater Depreciation Study
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study
Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint- Texas Coast Division	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric 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	43695	Xcel Energy	2014	Electric Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study

Dane Watson Testimony Appearances

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
Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service of Colorado	2014	Electric Depreciation Study
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study
Texas, New Mexico	Public Utility Commission of Texas	42004	Southwestern Public Service Company	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
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
North Carolina/South Carolina	FERC	ER13-1313	Progress Energy Carolina	2013	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power Company - Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General
Texas	Public Utility Commission of Texas	41474	Sharyland	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
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	Southwestern Public Service Company	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
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Texas Public Utility Commission	40824	Xcel Energy	2012	Electric Depreciation Study
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study
Texas	Texas Public Utility Commission	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Northern States Power Company - Minnesota	2012	Electric, Gas and Common Transmission, Distribution and General
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
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
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study
Texas	Texas Public Utility Commission	40020	Lone Star Transmission	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service of Colorado	2011	Electric Depreciation Study
Texas	Texas Public Utility Commission	39896	Entergy Texas	2011	Electric Depreciation Study
MultiState	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study
Mississippi	Mississippi Public Service Commission	2011-UN-184	Atmos Energy	2011	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Railroad Commission of Texas	10038	CenterPoint South TX	2010	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
Texas	Texas Railroad Commission	10041	Atmos Amarillo	2010	Gas Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service	2010	Electric Technical Update
Alaska	Regulatory Commission of Alaska	U-09-015	Alaska Electric Light and Power	2009-2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15963	Michigan Gas Utilities Corporation	2009	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study
Texas	Railroad Commission of Texas	9902	CenterPoint Energy Houston	2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service Company of Colorado	2009	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Tennessee	Tennessee Regulatory Authority	11-00144	Piedmont Natural Gas	2009	Gas Depreciation Study
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35763	Southwestern Public Service Company	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Wisconsin	Wisconsin	05-DU-101	WE Energies	2008	Electric, Gas, Steam and Common Depreciation Studies
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power Company - Minnesota	2008	Net Salvage
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	Southwestern Public Service Company	2008	Testimony – Depreciation
Multiple States	Railroad Commission of Texas	9762	Atmos Energy	2007-2008	Shared Services Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35717	Oncor	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	06-234-EG	Public Service Company of Colorado	2006	Electric Depreciation Study

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Arkansas	Arkansas Public Service Commission	06-161-U	CenterPoint Energy – Arkla Gas	2006	Gas Distribution Depreciation Study and Removal Cost Study
Texas, New Mexico	Public Utility Commission of Texas	32766	Southwestern Public Service Company	2005-2006	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Texas	Railroad Commission of Texas	9670/9676	Atmos Energy Corp	2005-2006	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9400	TXU Gas	2003-2004	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9313	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9225	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	24060	TXU	2001	Line Losses
Texas	Public Utility Commission of Texas	23640	TXU	2001	Line Losses
Texas	Railroad Commission of Texas	9145-9148	TXU Gas	2000-2001	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	22350	TXU	2000-2001	Electric Depreciation Study, Unbundling
Texas	Railroad Commission of Texas	8976	TXU Pipeline	1999	Pipeline Depreciation Study
Texas	Public Utility Commission of Texas	20285	TXU	1999	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	18490	TXU	1998	Transition to Competition

Dane Watson Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Public Utility Commission of Texas	16650	TXU	1997	Customer Complaint
Texas	Public Utility Commission of Texas	15195	TXU	1996	Mining Company Depreciation Study
Texas	Public Utility Commission of Texas	12160	TXU	1993	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	11735	TXU	1993	Electric Depreciation Study

Southwest Gas Corporation
Arizona Jurisdiction
Gas Utility Plant

Removal Cost Allocation Study
In Compliance With
Docket No. G-01551A-16-0107

ALLIANCE
CONSULTING GROUP

Southwest Gas Corporation
Arizona Jurisdiction
Gas Utility Plant

Removal Cost Allocation Study
In Compliance With
Docket No. G-01551A-16-0107

EXECUTIVE SUMMARY

Southwest Gas Corporation ("Southwest Gas" or "the Company") requested Alliance Consulting perform a removal cost allocation study to address the removal costs for Account 376 and 380, Mains and Services respectively in its Arizona properties noted for the Company's Arizona jurisdiction natural gas operations as ordered in Docket No, G-01551A-16-0107.

After reviewing the Company's processes for booking removal costs into the accumulated provision for depreciation before, during and after the 2015 period, we conclude that the Company has been using industry best practices in recording removal cost and no adjustments are needed to their process. Further, the 2015 activity which the Company agreed to address was caused by a pro-active program to retire non-conforming plastic pipe (M7000/M8000) consisting of inactive services, inactive service stubs and inactive mains as well as inadvertently excluding certain 2015 retirements from the net salvage analysis. After removing that activity from Company historical data and restoring the appropriate retirements, the results are consistent with prior Company history. Finally, the books and records of Southwest Gas Arizona are accurate as related to removal cost charges. No change is needed to the Company's accumulated depreciation for any accounts. All charges were appropriately booked as capital and no transfer to operation and maintenance or other account is necessary. The account balances of mains and services accumulated depreciation are fairly stated going forward into the Company's next rate case.

Southwest Gas Corporation
Arizona Jurisdiction
Gas Utility Plant

Removal Cost Allocation Study
In Compliance With
Docket No. G-01551A-16-0107

PURPOSE

Southwest Gas Corporation ("Southwest Gas" or "the Company") requested Alliance Consulting perform a removal cost allocation study for the Company's Arizona jurisdiction natural gas operations. The purpose of the removal cost allocation study is to comply with the terms of the settlement agreement in the Company's last general rate case, as ordered in Decision No. 76069. As agreed to by the Company, this study's objectives are as follows:

> In conjunction with the Company's next general rate case filing, SWG will perform a detailed and objective cost of removal study to determine the validity of significant increases in cost of removal charges recorded in 2015, and for any that may occur after 2015 and before the next rate case. In the meantime, the Company shall review the cost of removal charges recorded in mains and services accumulated depreciation accounts in 2015 to determine whether charges, if any, should be transferred to operations, maintenance, or other accounts. This review would help ensure the account balances of mains and services accumulated depreciation are fairly stated going forward into the next rate case. SWG shall provide the results of such study and review as part of its next general rate case filing.

BACKGROUND

In Docket No. G-01551A-16-0107, the Company showed increased removal cost in Accounts 376 and 380, Mains and Services, respectively. These are the Company's largest plant accounts, comprising more than 83% of the Company's plant as of December 31, 2015. Therefore, the Company agreed to conduct the subject removal cost study. Alliance's net salvage recommendations excluded the effect of the 2015 increase in the net salvage percentage. Alliance recommended negative 35 and negative 55 percent for Accounts 376 and 380, respectively. Decision No. 76069 adopted negative 30 and negative 55 percent respectively for Accounts 376 and 380. Tables 1&2 show the results for Accounts 376 and 380 which were reported in the depreciation study.

Table 1 - Removal Cost Account 376

Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %
2006	2,378,319	0	512,089	-512,089	-21.53%
2007	3,464,438	0	778,505	-778,505	-22.47%
2008	4,705,622	0	889,561	-889,561	-18.90%
2009	7,425,368	0	1,297,824	-1,297,824	-17.48%
2010	7,057,129	24,439	1,522,992	-1,498,553	-21.23%
2011	5,667,833	0	1,220,613	-1,220,613	-21.54%
2012	5,255,656	0	1,743,686	-1,743,686	-33.18%
2013	5,284,475	0	2,742,020	-2,742,020	-51.89%
2014	5,471,831	0	1,858,030	-1,858,030	-33.96%
2015	1,385,718	0	5,230,681	-5,230,681	-377.47%
Total	48,096,389	24,439	17,796,000	-17,771,561	-36.95%

Table 2 - Removal Cost Account 380

Activity Year	Retirement	Gross Salvage	Cost of Removal	Net Salvage	Net Salv. %
2006	4,041,947	0	1,383,267	-1,383,267	-34.22%
2007	3,990,321	0	1,780,272	-1,780,272	-44.61%
2008	3,035,470	0	1,834,578	-1,834,578	-60.44%
2009	4,733,764	0	1,729,355	-1,729,355	-36.53%
2010	4,074,380	0	1,639,128	-1,639,128	-40.23%
2011	6,173,739	0	1,540,264	-1,540,264	-24.95%
2012	5,083,477	0	1,653,716	-1,653,716	-32.53%
2013	3,398,449	0	2,269,607	-2,269,607	-66.78%
2014	4,340,904	0	2,987,831	-2,987,831	-68.83%
2015	10,178,924	0	27,095,366	-27,095,366	-266.19%
Total	49,051,375	0	43,913,385	-43,913,385	-89.53%

PROCESS

Alliance engaged in interviews and discussions with subject matter experts within the Company from operations, engineering, accounting, and other areas of management to gain a better understanding of how costs for removing and replacing a capital asset are being recorded, tracked, and allocated. During the 2015 and following periods, the Company used a compatible units ("CU") system for pipe, regulators, and other types of plant. In Alliance Consulting's experience, CU systems are used throughout the utility industry and are the predominant method of determining removal cost. Tasks are specified in the system with installation and removal units, e.g. 1,000 feet of 2-inch steel main being replaced with 2-inch' PE pipe. The computer software includes labor CUs, and the designer of each project estimated how many hours are necessary to complete each activity as well as which CU's are part of that task. For example, there is a CU called 3-man crew, where the contractor sends a 3-person crew who may have a backhoe or other heavy equipment needed to complete the job. The workers may have to dig 3 bell holes to abandon a main or service. The Company's estimating and construction management system uses a fixed cost per foot to abandon pipeline facilities that is computed from competitively bid and awarded pricing structure for the contractors used for every project. A Master Pipeline contract is used for routine capital work for new pipeline installations, relocations and replacements which has specific line items for each activity (including removal activities). The Company loads master contract line items (i.e. the cost for each activity that will be charged by the specific contractor) into the Field Operations Management System ("FOMS") which was the basis for these types of project estimates. Large, high-dollar projects are separately bid, and the design estimates are also generated in FOMS, however the contractor's bid costs are maintained in the Voucher section of the FOMS application. Invoices are recorded into PowerPlan, which is the continuing property records system for the Company and is integrated to function with FOMS information.

PowerPlan was implemented in 2008. Since the Company has used the software for more than 10 years with no significant changes in process, the removal cost results have been reasonably similar from year to year. Both new additions and removal cost are based on master pipeline contracts which are renegotiated every few years. The

Company nearly always abandons pipe in place, and only removes a main or service if it is in direct conflict with other newly installed facilities - typically facilities installed and owned by municipalities or governmental agencies. If removed, the removal cost would be high (likely in the range of the cost to install the new pipe). If the asset is physically removed from the ground, it becomes necessary to replace paving for pipe installed under streets, and older vintage steel pipe with coal-tar coating is assumed to contain asbestos, which requires additional environmental controls to protect workers and to dispose of the pipe as hazardous waste. Since this activity was infrequent, the removal of pipe from the ground was not a triggering event for the higher removal cost seen in 2015.

There is a vouchers application (within FOMS) that Engineering uses to house costs that may not have a CU (e.g. permit costs, contractor design services, special material and equipment, or contractor costs for competitively bid projects). The Company uses the CPI annually to update pricing of the CU's for the Master Pipeline contract in FOMS. In examining some of the tasks in the systems, Alliance finds that the gradual increase using CPI is similar to other best practices in the industry. The tables below show the change in pricing for two common tasks.

Table 4 – Task PVp20.25

Year	Task	Unit Price
2011	Rep/replace roadway substructure 6” base 4” cap over 500 ft	16.95
2012	Rep/replace roadway substructure 6” base 4” cap over 500 ft	17.09
2013	Rep/replace roadway substructure 6” base 4” cap over 500 ft	1723
2014	Rep/replace roadway substructure 6” base 4” cap over 500 ft	17.69
2015	Rep/replace roadway substructure 6” base 4” cap over 500 ft	17.73
2016	Rep/replace roadway substructure 6” base 4” cap over 500 ft	18.36
2017	Rep/replace roadway substructure 6” base 4” cap over 500 ft	19.01
2018	Rep/replace roadway substructure 6” base 4” cap over 500 ft	19.81

Table 5- Task PVp20.3

Year	Task	Unit Price

2011	Rep/replace asphalt 0-4 depth 101-500 Sq. ft.	8.84
2012	Rep/replace asphalt 0-4 depth 101-500 Sq. ft.	9.09
2013	Rep/replace asphalt 0-4 depth 101-500 Sq. ft.	9.37
2014	Rep/replace asphalt 0-4 depth 101-500 Sq. ft.	9.42
2015	Rep/replace asphalt 0-4 depth 101-500 Sq. ft.	9.51
2016	Rep/replace asphalt 0-4 depth 101-500 Sq. ft.	9.96
2017	Rep/replace asphalt 0-4 depth 101-500 Sq. ft.	10.09
2018	Rep/replace asphalt 0-4 depth 101-500 Sq. ft.	10.61

Beginning in 2014-2015, there was a significantly higher level of replacement/abandonment activity than in the past; this is attributed to the Company's pro-active program to abandon inactive services, inactive service stubs and inactive mains made up of M7000/M8000 polyethylene (PE) pipe. That activity impacted retirement and net salvage results in 2015 and in periods thereafter.

SPECIFIC ACTIVITY 2014 – PRESENT

Alliance interviewed Company engineers and operations personnel to determine if there were any specific programs or efforts that impacted net salvage for the accounts in question. The M7000/M8000 PE Inactive Service and Stub Abandonment Project (ISSAP) started in 2015. ISSAP is a proactive Company initiative to abandon or replace the M7000/M8000 pipe. At the beginning of 2015 (or late 2014), removal-only blankets were created (RB01600 - Mains and RB02600 - Services) to track the retirement and removal costs of mains and services that were abandoned (i.e. not replaced). Most of the activity was in services in the early periods but there was still some activity in mains. In the earlier periods of the project (e.g. 2015-2016), service and main stubs and no/low use services were identified and abandoned. The effect of this effort on removal cost is described later in the report. In 2017, the activity began to increase for mains. In Arizona, this project was competitively bid and there was one contractor generally dedicated to the work.

DEPRECIATION STUDY DATA - 2015 RETIREMENTS

In examining data provided by Southwest Gas, Alliance determined that the depreciation study did not capture the appropriate level of retirements. An inadvertent oversight occurred when Southwest Gas redefined the study to be based on year end 2015 data, as only 2015 transactional data was provided to Alliance for the update. The transaction year 2015 was adjusted and did not include retirement activity that physically occurred in prior years but was being unitized (reflected on the books) in 2015. The Company resets the vintage of the various retirement transactions to the year that the retirements actually occurred. As a result, the 2015 retirements were understated in the depreciation study. At the same time, the removal cost charges were not adjusted on the Company's books into prior years so the full level of removal cost related to the retirement that were restated into previous years were still included in the 2015 data. This inconsistency resulted in the retirements used in the net salvage analysis being too low (or alternatively, removal cost was too high based on the retirements reflected in 2015). Thus, net salvage percentages in 2015 appear much higher than they were in reality.

Table 6- Comparison of Retirement Amounts

Account	2015 Depr Study Retirements	Per Book Retirements	Difference
376	1,385,718	10,376,454	8,990,736
378	236,272	1,190,323	954,051
380	10,178,924	10,288,740	109,816
381	4,747,183	4,748,393	1,210
385	9,318	18,251	8,933
396	1,536	43,874	42,338

NET SALVAGE ACTIVITY THROUGH 2018

When the Company's net salvage history for mains and services is adjusted to consistently apply the retirements and removal cost in the transaction year that they were recorded on the books (i.e. per book with no adjustments), the following tables illustrate the net salvage percentages that would occur. The net salvage percentages in 2015 and following for Account 376 Mains are reasonably consistent across years 2015 and later.

Table 7 Unadjusted Retirements
Account 376

Year	Retirements	Removal Costs	COR %
2011	5,667,833	1,220,613	22%
2012	5,255,656	1,743,686	33%
2013	5,284,475	2,742,020	52%
2014	5,471,831	1,858,030	34%
2015	10,376,454	5,230,681	50%
2016	9,609,600	4,850,914	50%
2017	8,578,775	3,365,766	39%
2018	15,454,433	5,585,811	36%
Total	65,699,057	26,597,521	40%

Table 9 Unadjusted Retirements
Account 380

Year	Retirements	Removal Costs	COR %
2011	6,173,739	1,540,264	25%
2012	5,083,477	1,653,716	33%
2013	3,398,449	2,269,607	67%
2014	4,340,904	2,987,831	69%
2015	10,288,740	27,095,366	263%
2016	12,750,616	22,171,412	174%
2017	12,082,386	14,007,382	116%
2018	10,304,539	7,353,587	71%
Total	64,422,850	79,079,165	123%

However, there is another event that is acting on the cost of removal amounts that will further explain the remaining increases in 2015 and later years for Accounts 376 and 380.

BLANKET WORK ORDERS

In addition to the retirement adjustment discussed above, the two blanket M7000/M8000 work orders to remove inactive services, service stubs and dead-end mains serving no customers from service, which were initiated in 2015, produced large amounts of the removal cost reflected in the depreciation study. The results below show the retirement and net salvage activity produced by the proactive retirements. Most of the retirement activity was centered on Account 380, Services. It should be noted that these are "removal-only" blankets. In other words, the projects charged to these blankets are pipe that is being abandoned and not replaced. Therefore, the full cost of the project to disconnect a service (or main) from the system when there is no replacement is charged as removal cost. Removal-only projects have significantly higher removal cost (and negative net salvage percentages) than a replacement project since the common cost related to both the retirement and construction in a project can not be shared when there is only retirement activity. This higher level of removal cost and net salvage is demonstrated below in the charges related to the removal-only blankets.

Table 10 - Blanket Project for Mains
Account 376 RB016000

Year	Retirements	Removal Costs	COR %
2015	172,523	1,349,683	782%
2016	276,209	2,605,085	943%
2017	156,101	1,151,625	738%
2018	14,324	150,867	1053%
Total	619,157	5,257,260	849%

Table 11 - Blanket Project for Services
Account 380 RB026000

Year	Retirements	Removal Costs	COR %
2015	4,807,080	23,731,616	494%
2016	7,491,370	18,866,309	252%
2017	4,659,902	10,453,448	224%
2018	2,353,338	3,228,643	137%
Total	19,311,690	56,280,016	291%

If the retirement and net salvage activity from the removal-only project blankets were removed from the Company's history, the results of the net salvage analysis move back in line with the results from prior periods as shown below.

Table 12 Net Salvage History
Account 376 Adjusted

Year	Remove Blanket Project Activity Retirements	Remove Blanket Project Activity Removal Costs	COR %
2011	5,667,833	1,220,613	22%
2012	5,255,656	1,743,686	33%
2013	5,284,475	2,742,020	52%
2014	5,471,831	1,858,030	34%
2015	10,203,931	3,880,998	38%
2016	9,333,391	2,245,829	24%
2017	8,422,674	2,214,141	26%
2018	15,440,109	5,434,944	35%
Total	65,079,900	21,340,261	33%

Table 13 Net Salvage History
Account 380 Adjusted

Year	Retirements	Removal Costs	COR %
2011	6,173,739	1,540,264	25%
2012	5,083,477	1,653,716	33%
2013	3,398,449	2,269,607	67%
2014	4,340,904	2,987,831	69%
2015	5,481,660	3,363,750	61%
2016	5,259,246	3,305,103	63%
2017	7,422,484	3,553,934	48%
2018	7,951,201	4,124,944	52%
Total	45,111,160	22,799,149	51%

Since retirements and removal costs may not be fully synchronized (i.e. activity occurring in different transaction years), mild fluctuations in removal cost over time normally occur. With the adjustment for the 2015 retirement and removal-only blanket charges, the results of the net salvage analysis are consistent with the Company's prior history. The

Company's removal cost process follows industry best practice and there are no underlying issues related to the removal cost process used by the Company.

CONCLUSION

After review of the Company's removal cost results, the significant increases in removal cost (and percentages) were due to a pro-active abandonment projects for M7000/M8000 mains and services in the 2015-2018 timeframe and the failure of the depreciation study to pick up the restated 2015 retirements. The charges that were made to accumulated depreciation are correct and no adjustment should be made to the Company's plant accounting system for the subject accounts. The account balances for mains and services accumulated depreciation are fairly stated. In addition, the Company's accounting practices follow best practices used by gas utilities across the United States.

Tab 8

Direct Testimony
of
Randi L. Cunningham

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-19-0055

PREPARED DIRECT TESTIMONY
OF
RANDI L. CUNNINGHAM

ON BEHALF OF
SOUTHWEST GAS CORPORATION

MAY 1, 2019

Table of Contents
Prepared Direct Testimony
of

RANDI L. CUNNINGHAM

Appendix A – Summary of Qualifications of Randi L. Cunningham

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
RANDI L. CUNNINGHAM

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Randi L. Cunningham. My business address is 5241 Spring Mountain Road, Las Vegas, NV 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or Company) in the Regulation and Energy Efficiency department. My title is Regulatory Professional.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Arizona Corporation Commission (Commission), the Public Utilities Commission of Nevada (PUCN), and the California Public Utilities Commission (CPUC).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor the Company's overall revenue requirement and provide a summary of the test year results of operations and the major components of the Company's deficiency. I provide an overview of Southwest Gas' operations and cost allocation methods. I also sponsor the financial statements and statistical schedules in Schedule E, from Schedule E-1 to E-6 and E-8 and E-9, and the projections and forecasts in Schedule F.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- A summary of the results of operations for the Company's Arizona rate jurisdiction, including test year results, and the revenue deficiency as shown on Schedule A-1.
- The major components of the revenue deficiency in this application.
- An overview of Southwest Gas' natural gas utility operations, including a description of the Company's state and federal ratemaking jurisdictions.
- The methodologies employed by Southwest Gas for cost responsibility and allocations (excluding the Company's class cost of service study) contained in Schedule C-1.
- Southwest Gas' adjusted test year income statements included in Schedule C-1, with the exception of Sheet 2, and the Company's pro forma adjustments included in Schedule C-2.
- The computation of the gross revenue conversion factor and state and federal income tax rates as shown on Schedule C-3.
- The computation of the Company's rate base, as presented in Schedule B, and the ratemaking adjustments to determine the appropriate level of cost of service.

- The fair value rate of return (FVROR) requested by the Company, and the appropriate FVROR calculation for incremental investments undertaken by the Company between general rate cases (GRC).

II. SUMMARY OF RESULTS OF OPERATIONS

Q. 7 What is the test year in this application?

A. 7 Southwest Gas, as part of the Settlement Agreement (Settlement) authorized in Decision No. 76069, agreed that it would not file its next GRC prior to May 1, 2019. Since the Company determined that a revenue deficiency exists, it has filed this GRC with a test year of the twelve months ended January 31, 2019.

The recorded test year results were adjusted to annualize and normalize the effects of known and measurable changes that occurred through January 31, 2019, and to include certain post-test year costs that were effective after the end of the test year as discussed further below.

Q. 8 How does the Company determine if a revenue deficiency exists?

A. 8 A revenue deficiency exists when the Company's annualized and normalized revenue at its present rates is less than the Company's adjusted cost of service at its proposed weighted average cost of capital.

Q. 9 What does the term "revenue" mean in the context of the Company's revenue deficiency?

A. 9 The term "revenue" in this instance refers to the non-gas and non-surcharge revenues that Southwest Gas receives through base rates. Because there is a separate purchased gas mechanism to ensure that the Company's customers only pay the actual cost incurred by the Company to purchase natural gas (i.e. Southwest Gas earns no profit on the natural gas commodity), these revenues are excluded from the GRC. Similarly, because Southwest Gas has separate regulatory mechanisms to recover certain other costs outside of base rates, these revenues are also excluded from the GRC. Another term that is used interchangeably with “revenue” in this context is “margin”.

Q. 10 What is the Company’s revenue deficiency in its Arizona operations, and how was it determined?

A. 10 The Company’s revenue deficiency is approximately $57 million. Schedule A-1, Sheet 2, Column (e) shows that annualized margin at present rates needs to be adjusted upward to approximately $518.2 million; this yields a rate of return (ROR) of 5.98 percent on rate base of $1,991,543,072. The Company is requesting a FVROR of 5.98 percent on fair value rate base (FVRB) of $2,612,828,261. Accordingly, to produce a 5.98 percent FVROR, a revenue increase of approximately $57 million is required. Please refer to the prepared direct testimony of Company witnesses Theodore K. Wood and Robert B. Hevert for the Company’s requested cost of capital.

III. MAJOR COMPONENTS CONTRIBUTING TO THE DEFICIENCY

Q. 11 What are the major causes of the Company’s revenue deficiency?

A. 11 There were two major changes to the Company’s cost of service since the last GRC, which was filed with a test year ended November 30, 2015. First, the Company made a significant amount of capital investments in its natural gas distribution system. Second, the Tax Cuts and Jobs Act (Tax Reform) which became law December 22, 2017 reduced the corporate income tax rate from 35 percent to 21 percent, and the cost of service must be updated to fully reflect the impacts of this change. In addition, authorized revenues need to be updated to reflect the overall changes in the level of operating expenses currently experienced by the Company.

The impact to the cost of service resulting from increased capital investments and related depreciation and property tax expenses is approximately $101.9 million. Of this amount, approximately $12.9 million relates to the post-test year addition of the Liquefied Natural Gas (LNG) storage facility previously approved by the Commission, and approximately $20.0 million relates to other post-test year plant additions.

The two primary impacts to the cost of service resulting from Tax Reform are: 1) the change in the federal income tax rate from 35 percent to 21 percent; and 2) the reduction in income tax expense due to the amortization of excess deferred taxes. This reduced the revenue requirement by approximately $47.4 million. The tax changes are discussed further below and in the prepared direct testimony of Company witness Byron C. Williams.

Q. 12 What is the Company's proposed annual percentage increase over revenue at present rates?

A. 12 The proposed annual percentage increase is 8.1 percent, which is calculated by dividing the $57 million proposed rate increase over revenue at present rates of approximately $699.8 million.

Q. 13 Please describe the Post-Test Year (PTY) adjustments the Company included as part of its cost of service in this application.

A. 13 Consistent with prior GRCs, Southwest Gas included select PTY adjustments, primarily consisting of the following: 1) the 2019 wage increase and twelve months of PTY within-grade movement; 2) software projects expected to close through December 31, 2019 and non-revenue producing plant additions anticipated through July 31, 2019; and 3) the plant and annualized operations and maintenance (O&M) expense related to the LNG storage facility. These items are addressed later in my testimony.

Q. 14 Why has Southwest Gas included these PTY items in its application?

A. 14 In the Company's prior Arizona GRCs, the Commission has allowed adjustments similar to those the Company has proposed in this proceeding if the events are known or reasonably certain to occur and are measurable prior to hearing. By including these PTY adjustments, the proposed cost of service will more accurately reflect the level of costs Southwest Gas will incur to serve its end of test year customer base when the rates approved in this proceeding will be effective.

Q. 15 Do the Company's PTY adjustments adhere to the matching principle?

A. 15 Yes. Only non-revenue producing plant is included in the PTY plant adjustments. The Company's customers at the end of the test year are the primary beneficiaries of these capital expenditures and will continue to be the primary beneficiaries during the rate effective period. Consequently, the inclusion of PTY plant in rate base more accurately matches the Company's investment needed to serve the customers on its system at the end of the test year and results in just and reasonable rates.

IV. OVERVIEW OF NATURAL GAS OPERATIONS

Q. 16 Please provide a brief overview of Southwest Gas' natural gas operations.

A. 16 Southwest Gas is a natural gas local distribution company, providing service to over 2.0 million customers in three states. At the end of the test year, Southwest Gas served nearly 1.1 million customers in Arizona, comprising approximately 53.3 percent of its total customer base. Southwest Gas also has a wholly-owned subsidiary, Paiute Pipeline Company (Paiute), that operates as an intrastate pipeline and is regulated by the Federal Energy Regulatory Commission (FERC).

Southwest Gas' operations are divided geographically into five operating divisions: Central Arizona, Southern Arizona, Southern California, Northern Nevada, and Southern Nevada. Each division operates independently of the others and may include portions of multiple ratemaking jurisdictions. All divisions are supported by staff located at the Company's corporate headquarters.

At the state level, Southwest Gas' retail gas utility operations currently consist of six rate jurisdictions: Arizona, subject to the regulation of the Commission; Southern Nevada and Northern Nevada, subject to regulation by the PUCN; and Southern California, Northern California, and South Lake Tahoe, California, subject to regulation by the CPUC. Southwest Gas' remaining two rate jurisdictions, Paiute and Southwest Gas Transmission Company (SGTC), are both regulated by the FERC.

V. JURISDICTIONAL COST RESPONSIBILITY AND ALLOCATIONS

Q. 17 Briefly describe how costs associated with Southwest Gas' natural gas operations are treated in this application.

A. 17 Both operating and capital costs are incurred at the Arizona district level and at the corporate level. Operating costs are also incurred at the Southwest Gas Holdings Inc. (Holding Company) level. Costs incurred at the district level are charged directly to the appropriate rate jurisdiction. Costs incurred at the corporate level may be charged directly to one or more rate jurisdictions if the cost/activity was incurred on its behalf (i.e., "corporate direct" costs). In instances where corporate costs are beneficial to all the Company's rate jurisdictions, or where the effort of tracking the jurisdictional allocation of the costs is not practical, such costs are allocated to all rate jurisdictions (i.e. “common” or “system allocable” costs). Costs that are not retained at the Holding Company level are allocated to Southwest Gas and Centuri Construction Group (Centuri)[1] based on the relative equity of each. The Holding Company costs that are allocated to Southwest Gas are system allocable costs since they benefit all the Company’s rate jurisdictions. No costs that were incremental due to the formation and operation of the Holding Company are allocated to Southwest Gas. The Holding Company costs that are allocated are similar to the costs that were incurred by the Southwest Gas prior to the formation of the Holding Company, such as Board of Director-related costs and financing costs to the extent that Southwest Gas uses the proceeds.

Q. 18 What are system allocable costs?

A. 18 System allocable costs consist primarily of administrative and general (A&G) expenses, the costs associated with intangible plant (mainly software) and general plant used to support the corporate administrative staff.

Q. 19 How does the Company allocate system allocable costs to Paiute and SGTC?

A. 19 System allocable A&G expenses (except Account 924, Property Insurance) are first allocated to Paiute and SGTC using the Modified Massachusetts Formula (MMF), a FERC-authorized methodology that is calculated on Schedule C-1, Sheet 18. Property insurance is allocated using an insurable property factor (WP Schedule C-2, Adjustment No. 11, Sheets 3-4). Paiute is also charged a

[1] Centuri is a non-regulated infrastructure services provider and a wholly-owned subsidiary of the Holding Company.

rental fee for its use of system allocable intangible and general plant.

System allocable costs that are allocated and charged to Paiute are transferred to and recorded on Paiute's books monthly, and to SGTC's books annually. Consequently, system allocable A&G expenses recorded on Southwest Gas' books are net of the allocations to Paiute and SGTC.

For this application, the MMF, the insurable property factor, and the Paiute rental charge were recalculated using end of test year data. The resulting pro forma adjustment is presented in Adjustment No. 11, which is discussed in further detail later in my testimony.

Q. 20 After system allocable costs are allocated to Paiute and SGTC, how are the remaining costs allocated to Southwest Gas' retail rate jurisdictions?

A. 20 Property insurance costs are allocated to each retail rate jurisdiction using the same insurable property factor discussed previously, and the remaining system allocable costs are allocated using the 4-Factor Allocation Methodology (4-Factor) described below.

Q. 21 Please describe the 4-Factor.

A. 21 The 4-Factor is based on the average of four equally-weighted components: (a) direct operating expense; (b) average gross plant; (c) direct operating labor; and (d) average number of customers. The 4-Factor has been used for ratemaking purposes by Southwest Gas since the 1950s and has been accepted and approved by each of the Company's state regulatory commissions. Schedule C-1, Sheet 17 provides the development of the 4-Factor allocation percentages for the test year.

VI. OPERATING EXPENSES

Q. 22 Please describe and explain Southwest Gas' Schedule C-1.

A. 23 Schedule C-1 begins with the Company's adjusted income statement on Sheet 1, and the subsequent sheets summarize recorded and adjusted O&M expenses, A&G expenses, depreciation and amortization expenses, other taxes, and income taxes. Schedule C-1 is rounded out by the calculations supporting the 4-Factor and MMF allocations, which are described in greater detail above.

Q. 24 Please describe and explain Southwest Gas' Schedule C-2.

A. 24 Schedule C-2 provides a summary, by function, of all the pro forma adjustments proposed in this proceeding. The remaining C-2 schedules provide support for each pro forma adjustment.

Q. 25 Please describe and explain Southwest Gas' Schedule C-3.

A. 25 Schedule C-3 shows the calculation of the gross revenue conversion factor, and the income tax rates used in this application.

Adjustment No. 3 – Labor and Labor Loading Annualization

Q. 26 Please describe and explain Adjustment No. 3 - Labor and Labor Loading Annualization.

A. 26 Adjustment No. 3 annualizes the labor and related labor loadings of Arizona and Corporate employees employed by the Company at the end of the test period – January 31, 2019. This adjustment increases operating expenses by $3,609,697.

The labor and labor loading annualization adjustment includes three components. First, a salary annualization is made for all Arizona and corporate employees with salaries in effect at the end of the last pay period beginning prior to January 31, 2019. Second, labor loadings are annualized or normalized at the end of the test year and those costs are applied to the employees on Southwest Gas' payroll at the end of the test year. Finally, the labor adjustment reflects an estimated overall 2.70 percent general wage increase to be effective in June 2019, along with additional wage increases as a result of within-grade movement during the twelve months subsequent to the end of the test year (i.e., through January 2020).

Q. 27 Why is it appropriate to adjust labor expense for the 2019 general wage increase and twelve months of within-grade movement?

A. 27 Under current Commission guidelines for processing major rate applications, it is not expected that the hearing in this proceeding will be conducted before January 2020. Historically, the Company has granted general wage increases effective each June, after being approved by the Company's Board of Directors in May. Therefore, the 2019 general wage increase and PTY within-grade wage increases will be known and measurable prior to the hearing in this proceeding. As such, Staff and other intervenors will have an opportunity to verify and quantify the 2019 general wage increase and PTY within grade wage movement.

Q. 28 Does this PTY adjustment adhere to the matching principle?

A. 28 Yes. This adjustment only applies to employees on the Company's payroll at January 31, 2019, the end of the test year. It does not apply to any employees hired after January 31, 2019 to meet customer growth, changes to work requirements, etc. Therefore, the number of employees at the end of the test year is synchronized with test year customers that those employees serve. Indeed, this adjustment preserves the matching principle by ensuring rates approved in this proceeding better reflect the costs that will be incurred by the Company during the period rates will be effective. This adjustment simply recognizes that by the time rates become effective, test year customers will be served by test year employees who, on average, will be paid more than the wages that were in effect at the end of the test year.

Q. 29 Have previous Commission rulings in the Company's rate applications addressed this adjustment?

A. 29 Yes. The Commission has consistently approved Southwest Gas' post-test year wage increases. In Decision No. 70665, the Commission concluded that Southwest Gas' post-test year wage increase ". . . should be allowed because it is a known and measurable expense that is being incurred by the Company on a going-forward basis. Because the post-test year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenue and expenses."

Q. 30 Please describe the labor loading process.

A. 30 Benefits, payroll taxes and the current service cost related to the Company's retirement plans are accumulated at the corporate level. These costs are then distributed among the various rate jurisdictions through a labor loading process. The labor loading rate is adjusted at the beginning of each year, based on budgeted pensions, benefits, paid time off, payroll taxes, and expected employee levels. The labor loading process applies the labor loading rate to each labor dollar, assigning an appropriate amount of pensions, benefits, paid time off, and payroll taxes to each account to which labor has been charged.

Q 31 How were labor loadings for Arizona and corporate employees annualized or normalized in this application?

A. 31 Southwest Gas normalized the portion of retirement benefits subject to the labor loading process, which consists of the current service costs for the basic retirement plan (pension), post-retirement benefits other than pension (PBOP), and the supplemental executive retirement plan (SERP), based on a three-year average. The Company used the amounts from the three most recent actuarial studies, which are also used by the Company to accrue related expenses, as the basis for the normalization. Non-service costs are no longer subject to the labor loading process and are included in A&G expense, as described in more detail below.

Consistent with prior Commission decisions, the Company removed certain items recorded in Account 926 from the cost of service, such as costs related to service awards, retirement gifts and parties, and employee recognition. Also, adjustments were made to remove out of period charges from the test year, and to bring in test year charges recorded out of period.

In addition, payroll taxes, 401k match, and indirect time were adjusted for the impact of annualizing payroll and overtime. For the remaining costs in Account 926, recorded test year costs were used as the basis for the annualization. These adjustments are consistent with prior Commission decisions.

Q. 32 How are labor loading costs allocated to Arizona?

A. 32 There were two methods used to allocate labor loading costs to Arizona. First, the current service cost of pension, PBOP, and SERP, along with the total cost of the executive deferred compensation plan, and employee investment plan (401k) was allocated based on each rate jurisdiction's labor cost as a percentage of total Company labor. Second, for the remaining benefits, a cost per employee was calculated based on the adjusted costs divided by the total number of Company employees at the end of the test year. The cost per employee was multiplied by the number of Arizona jurisdictional employees at the end of the test year to determine the amount allocated to Arizona for ratemaking purposes.

Q. 33 Were there any changes in the way Southwest Gas accounts for its retirement benefits since the Company's last GRC?

A. 33 Yes. As of January 1, 2018, the Company adopted Financial Accounting Standard Board (FASB) "Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost." The update requires that an employer report the service cost component in the same line item or items as other compensation costs arising from services rendered by the employees during the period. The other components of net benefit cost are required to be presented in the income statement separately from the service cost component. The update also allows only the service cost component to be eligible for capitalization when applicable. Due to the complexity, administrative burden and cost of maintaining a separate set of plant records and depreciation for regulatory purposes separate from those that would be required for U.S. Generally Accepted Accounting Principles (GAAP) purposes (due to the portion no longer able to be eligible for capitalization under GAAP), management elected to implement the new GAAP for not only external financial reporting purposes but also for regulatory purposes. The FERC also recognized these conditions (FERC Docket No. AI18-1-000) and permitted a change to capitalize only service-related components, while indicating the non-service cost components would be recognized in FERC account 926. Non-service cost components are no longer included in the labor loading process and are now included in A&G expense. As shown in Schedule C-2, Sheet 2, the Company created a new subaccount for FERC account 926 to record non-service related pension costs and allocated this subaccount to each of its state ratemaking jurisdictions based on the 4-Factor methodology.

Over time, this accounting change will result in a lower revenue requirement, since the Company can no longer capitalize and earn a return on non-service related pension costs effective January 1, 2018. The system allocable three-year normalized amount of this cost for is $18.5 million, of which $9.8 million was allocated to Arizona.

Q. 34 Once the annualized labor and labor loadings were calculated, how was the adjustment determined?

A. 34 The annualized labor and labor loadings were assigned to each account based on the historical test year relationships. For example, during the test year, approximately 67 percent of Arizona direct labor and loadings were charged to O&M accounts. Therefore, 67 percent of the annualized Arizona direct labor and loadings were assigned to O&M accounts. The difference between the annualized labor and loadings assigned to the O&M accounts and the recorded labor and loadings is the adjustment for that account. Since 67 percent of the annualized Arizona direct labor and loadings were assigned to O&M, the remaining 33 percent were assigned to capital and deferred accounts, and do not impact the revenue requirement requested in this application. A similar assignment was performed for corporate staff annualized labor and loadings to determine the adjustment required. The adjustment described above for non-service retirement benefit costs is included in the total for this adjustment.

Adjustment No. 4 – Call Center and Customer Support Allocation and Annualization

Q. 35 Please explain Adjustment No. 4 - Call Center and Customer Support Allocation and Annualization.

A. 35 This adjustment allocates the proper percentage of this function to Arizona customers. This adjustment increases operating expenses by $73,158.

Q. 36 Please describe the Company's call center and customer support function.

A. 36 There are presently three customer assistance call centers in Southwest Gas' service territory: Phoenix, Tucson, and Las Vegas, Nevada. There are also contracted remote agents. Customers call a toll-free telephone number, and the call is routed to the next available agent, no matter where that agent is located. The agents are trained to respond to customer inquiries regardless of where the customer is located. There are also Company employees who provide back office customer support primarily in Victorville, California and Carson City, Nevada. All call centers and both customer support locations handle customer inquiries and reporting for the entire Company.

Q. 37 Why is an adjustment necessary to properly allocate these costs to Arizona?

A. 37 Certain call center and customer support function costs may be charged directly to an operating division, while these functions support the entire Company. As such, the test year costs are aggregated on a total company basis, and then reallocated to Arizona based on number of customers, which is the Factor IV component of the 4-Factor discussed earlier in my testimony. The adjustment reflects the difference between the amount recorded on Southwest Gas' books and the reallocated amount.

Adjustment No. 5 – Cost of Service Analysis

Q. 38 Please explain Adjustment No. 5 - Cost of Service Analysis.

A. 38 Southwest Gas conducted an analysis of its operating expenses to: 1) determine if there were costs recorded during the test year for which Southwest Gas is not requesting recovery in this proceeding; 2) adjust recorded expenses so a full year's worth of expense is reflected - no more and no less; 3) annualize items with significant cost changes; and 4) determine whether the test year contains material, non-recurring costs. Adjustment No. 5 reflects the results of this analysis. The amounts removed from and added to the cost of service are summarized by account in Schedule C-2, Adjustment No. 5, and the supporting workpapers categorize all transactions by the type of cost. Note that any items found in Account 926 are addressed in Adjustment No. 3. This adjustment reduces operating expenses by $1,129,536.

Adjustment No. 6 – Employee Vehicle Compensation

Q. 39 Please explain Adjustment No. 6 - Employee Vehicle Compensation.

A. 39 The Company recently implemented a new policy to replace the Company-owned vehicles provided to employees with a title equivalent to Director or above with a stipend to be used for a vehicle which meets certain conditions as specified by the Company. Adjustment No. 6 removed all vehicles assigned to a Director or above from rate base along with the O&M costs related to these vehicles and included the annualized stipends for each Director or above employee employed by the Company at the end of the test year. This adjustment is necessary to synchronize the cost of service with current Company policy. This adjustment increases operating expenses by $331,007 and reduces rate base by $752,493. This adjustment's impact to amortization expense is addressed in Adjustment No. 13, and its impact to deferred taxes is addressed in Adjustment No. 19.

Adjustment No. 7 – Uncollectible Expense Annualization

Q. 40 Please explain Adjustment No. 7 - Uncollectible Expense Annualization.

A. 40 Adjustment No. 7 annualizes the recorded amounts in Account 904, Uncollectible Expenses, to reflect the test year net closing bill write-offs as a percentage of gross revenues. The write-off percent applied to present revenues determines the annualized amount, which is then compared to the recorded uncollectible expense to determine the adjustment amount. This adjustment is consistent with those approved in Southwest Gas' last several rate cases. This adjustment decreases operating expenses by $81,178.

Adjustment No. 8 – Not Used

Adjustment No. 9 – Self-Insured Retention

Q. 41 Please explain Adjustment No. 9 - Self-Insured Retention.

A. 41 Adjustment No. 9 adjusts the recorded self-insured accruals charged to Account 925 during the test year to a normalized level.

Q. 42 What was the Company's level of self-insurance for general liability claims at the end of the test year?

A. 42 The Company is self-insured for up to $1 million of claims expense for each occurrence (per occurrence component). To the extent that a specific claim exceeds $1 million, the Company is self-insured for the excess over $1 million up to an aggregate (aggregate component) of $4 million. Once the $4 million aggregate is reached, any amount paid above the $4 million is the responsibility of the insurance carrier.

The up to $1 million per occurrence component has no annual limit as to the number of claims, is claim specific, and does not include costs emanating from more than one rate jurisdiction. Indeed, the per occurrence component of injuries and damages expense should be treated as a direct jurisdictional expense.

Q. 43 Please explain the accounting for the self-insured portion of liability claims.

A. 43 When an incident is identified that may require payment, the Company accrues the estimated payment as a self-insured retention expense. The entry is a debit to Account 925, Injuries and Damages, and a credit to Account 228.2, Accumulated Provision for Injuries and Damages. Once the outcome of the claim becomes final, any costs paid are charged against the accrual in Account 228.2. If the amounts paid are different than the amount accrued, then the net difference is removed from Account 228.2 and charged back against Account 925.

Q. 44 Given the method used to account for the self-insured portion of liability claims, does the test year expense reflect on-going operations?

A. 44 No. It is not unusual to have fluctuations in the net charges to Account 925 from period-to-period because of the nature of the method used to account for this process, and the fact that large claims that reach the $4 million aggregate do not occur every year. This can result in Account 925 having an expense level during any given recorded period not being representative of on-going operations. For this reason, it is appropriate to normalize this cost based on claims experience over the last ten years.

Q. 45 Please explain the normalized adjustment to self-insured expense.

A. 45 The Company used a ten-year average of self-insured amounts to normalize this expense for ratemaking purposes. Schedule C-2, Adjustment No. 9, shows that the ten-year average of Arizona direct claims is $790,608 compared to the test year amount of $0, requiring a $790,608 adjustment. The ten-year average system allocable expense is $150,885 compared to the test year amount of $600,000, requiring a $449,115 downward adjustment. After allocating a portion of this expense to Paiute, the Arizona portion of the system allocable portion of this adjustment is a decrease of $238,800. The total impact of this adjustment on Arizona's operating expenses is $551,808.

Adjustment No. 10 – AGA Dues

Q. 46 Please explain Adjustment No. 10 - AGA Dues.

A. 46 Adjustment No. 10 removes $12,011 from operating expenses, which is the portion of the Company's dues to the American Gas Association (AGA) identified as lobbying in nature.

Adjustment No. 11 – Paiute Pipeline/SGTC Allocation Annualization

Q. 47 Please explain Adjustment No. 11 - Paiute Pipeline/SGTC Allocation Annualization, which you previously referred to in your response to Question No. 19.

A. 47 Adjustment No. 11 annualizes the system allocable A&G amounts allocated to Paiute through the MMF allocation methodology, the insurable property factor, and the rent revenue that Southwest Gas received from Paiute for the test year ended January 31, 2019. The supporting workpapers to Adjustment No. 11 show the detailed calculations needed to derive the Paiute rent expense and insurable property factor at January 31, 2019. This adjustment is consistent with the methodology approved by the Commission in the Company's last several rate cases.

The annualized MMF allocation factors are also used in the pro forma adjustments that impact system allocable A&G costs, in order to allocate a portion of the adjustment to Paiute and SGTC before calculating the portion that is allocated to Arizona. This adjustment reduces operating expenses by $290,345.

Adjustment No. 12 – Rate Case Expense

Q. 48 Please explain Adjustment No. 12 - Rate Case Expense.

A. 48 The Company estimated the incremental costs that would be incurred to prepare and process this GRC, including printing, postage, court reporting, noticing, publication, travel, and outside consultants. The total incremental costs are divided by three, which is roughly equal to the number of years in one rate case cycle, to calculate an annual amortization to Account 928. The adjustment, which increases operating expenses by $70,108, is the difference between this new amortization amount and the amount of rate case expense amortized on the Company's books during the test year.

Adjustment No. 13 – Depreciation and Amortization Expense

Q. 49 Please explain Adjustment No. 13 - Depreciation and Amortization Expense.

A. 49 Adjustment No. 13 annualizes depreciation and amortization expense based on adjusted plant in service at January 31, 2019, using currently approved depreciation rates. The recorded test year amortizations in System Allocable FERC account 303 that will expire on or before December 31, 2019 were removed to synchronize with the PTY Plant adjustment. This adjustment also updates the System Allocable depreciation rates to synchronize with the depreciation study[2] approved by the PUCN December 24, 2018, as part of the Company's recent Nevada GRC, which reduced this adjustment by $43,120. This adjustment increases operating expenses by $14,380,183.

Q. 50 Please explain why an adjustment is necessary to annualize depreciation and amortization expense for the test year.

A. 50 This adjustment is necessary to synchronize the depreciation and amortization expense with the plant in service at the end of the test year, as adjusted. Like many utilities, Southwest Gas employs a depreciation convention based on the month the plant was first placed into service. Southwest Gas begins depreciation the month after the plant was first placed in service, and in turn, takes a full month's depreciation in the month it is removed or retired from service. As a result, plant that is placed in service or retired after the beginning of the test year has a partial year's depreciation expense recorded on the books of the Company. To allow Southwest Gas the opportunity to recover its reasonable and necessary operating expenses and to avoid charging customers for assets removed or retired from service, depreciation and amortization must be annualized based on adjusted end of test year plant balances. This adjustment accomplishes those objectives and is consistent with the methodology approved by the Commission in the Company's previous rate cases.

[2] A depreciation study was not filed for Arizona plant. The most recent study was performed approximately three years ago and submitted in Docket No. 16-0107.

Q. 51 Did the Company make an additional adjustment for the amortizations related to System Allocable Miscellaneous Intangible Plant?

A. 51 Yes. Most of the items in system allocable miscellaneous intangible plant (FERC account 303) are software projects with three to five-year amortization periods. These amortization periods are roughly equivalent to the Company's Arizona rate case cycle. Absent an adjustment, customers may end up double-paying for certain projects through rates, while never paying for other projects. To mitigate this potential outcome, the Company proposes an adjustment to remove all projects with an amortization period expiring December 31, 2019 or earlier. This adjustment is required to match with the Company's PTY Plant adjustment for FERC account 303, where estimated amounts for projects expected to be closed to plant on or before to December 31, 2019 were added to rate base. This is a conservative adjustment because many small software projects spend a relatively short time in construction work in progress before being transferred to plant. Consequently, between the date this rate case was prepared and December 31, 2019, more projects may close to plant than are indicated by the estimated balances included in the Company's application. Indeed, this adjustment strikes a fair balance between project amortizations that will expire shortly after the end of the test year, and projects commencing amortization and serving customers when rates from this proceeding go into effect. Further, the Company's estimated amounts can be verified by intervening parties.

Adjustment No. 14 – Taxes Other Than Income

Q. 52 Please explain Adjustment No. 14 – Taxes Other Than Income.

A. 52 Adjustment No. 14 annualizes property taxes on the Company's adjusted investment in plant and materials as of the end of the test year. For Arizona properties, the Company determines an estimated full cash value by using adjusted net plant in service at January 1, 2019, adding materials and supplies, and subtracting transportation equipment and land rights. The estimated full cash value is then multiplied by the assessment ratio of 18 percent to determine the assessed value. The assessed value is then multiplied by the composite property tax rate of 13.66 percent, which is then reduced by capitalized property taxes and increased by the Salt River Tribe Assessment[3] to determine the annualized property tax expense. The Company is proposing an adjusted test year property tax amount of $57,667,484, which would be the authorized amount that the Company would balance to in its Property Tax Deferral Mechanism if the Commission accepts the Company's proposed assessed value. There is also an adjustment to reduce miscellaneous taxes by $18,226 to remove items expensed during the test year that are non-recurring. This adjustment increases operating expenses by $15,911,411.

Adjustment No. 15 – Interest on Customer Deposits

Q. 53 Please explain Adjustment No. 15 - Interest on Customer Deposits.

A. 53 As discussed in the prepared direct testimony of Company witness Matthew D. Derr, the Company is proposing a tariff change to Rule 3 to update the customer deposit interest rate annually, to be more in line with other utilities. Adjustment

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[3] The Salt River Tribe Assessment is separately identified since it is not subject to balancing in the Property Tax Deferral Mechanism.

No. 15 synchronizes interest expense on customer deposits based on the interest rate proposed by the Company with the amount of customer deposits used as a rate base reduction. The difference between the adjusted amount and the recorded amount is the adjustment. Consistent with prior Commission decisions, interest expense is treated as an above-the-line expense. This adjustment decreases operating expenses by $1,222,444.

Adjustment No. 16 – Regulatory Amortizations

Q. 54 Please explain Adjustment No. 16 – Regulatory Amortizations.

A. 54 Adjustment No. 16 removes recorded test year regulatory amortizations from base rates that are recovered through the Demand Side Management Program (DSM) surcharge and the Transmission Integrity Management Program (TRIMP) surcharge. In addition, the Company is requesting to add three new regulatory amortizations related to the following regulatory assets and liabilities: Property Tax Mechanism, the Tax Reform Surcredit, and the DSM surcharge overcollection and to amortize these balances over a typical rate case cycle. This adjustment reduces operating expenses by $10,248,717 in Account 407.3 and increases operating expenses by $49,800 in Account 406.

Q. 55 Please explain the regulatory amortization for the Property Tax Mechanism.

A. 55 As part of D.76069, the Company was authorized to establish a Property Tax Mechanism. This mechanism allows the Company to defer any changes in property tax expense from the amount authorized and requires that the accumulated balance be recovered or refunded in the Company's next GRC.

Q. 56 What was the cumulative balance of the Property Tax Mechanism at the end of the test year?

A. 56 At January 31, 2019 the balance was a liability of $6,822,585. In other words, the Company overcollected property taxes during the time that rates from the prior GRC were authorized through January 31, 2019, and this liability needs to be returned to customers over the next rate case cycle.

Q. 57 Please explain the regulatory amortization for the Tax Reform Surcredit.

A. 57 After the Tax Reform was signed into law, Docket No. AU-00000A-17-0379 was opened to address the impact of the Tax Reform on current utility rates. D.76595 of that docket required companies such as Southwest Gas to apply regulatory accounting treatment, which included the use of regulatory assets and liabilities, to address all impacts from the enactment of the Tax Reform for possible future ratemaking treatment.

Pursuant to D.76595, the Company filed an Application April 2, 2018 requesting approval to establish a process to timely and efficiently flow back to customers 100 percent of the benefits of the Tax Reform. D.76798 ordered Southwest Gas to refund its annual federal income tax expense savings of $20,001,916 in two parts: 1) a one-time bill credit to refund tax savings from January through July 2018; and 2) a per therm bill credit from August 2018 until rates from this proceeding are effective.

Q. 58 What was the balance in the tax refund regulatory accounts at December 31, 2018?

A. 58 The one-time bill credit portion was $2,188,214 under-refunded, and the per therm bill credit was $360,512 over-refunded at December 31, 2018. Thus, there is a net $1,827,702 that is to be refunded to customers.

Q. 59 How does the Company propose to return the $1,827,702 to customers?

A. 59 Rather than address this liability as a true-up in a separate proceeding, the Company is proposing to include this amount in this GRC and refund it over a typical rate case cycle.

Q. 60 How long will the existing tax refund credit remain in place?

A. 60 It will remain in place until rates from this proceeding are effective.

Q. 61 Please explain the regulatory amortization for the DSM Surcharge Overcollection.

A. 61 As of December 31, 2018, the Company was overcollected by $1,703,252 for its DSM surcharge. After discussions with Commission Staff, it was determined that the Company would refund this overcollection through an adjustment in this GRC.

Q. 62 The Company is proposing to amortize these regulatory assets and liabilities over three years. Why is three years appropriate?

A. 62 To ensure the timely credit of these amounts owed customers, the Company proposes to clear the above-mentioned regulatory assets and liabilities over a typical rate case cycle. Consistent with the Company's proposed amortization period for rate case expense discussed above, three years approximates one rate case cycle.

VII. EMPLOYEE COMPENSATION EXPENSE

Q. 63 Please describe the Company's compensation philosophy.

A. 63 Southwest Gas' compensation philosophy aims to implement compensation programs that: (1) elicit strong performance by the Company's management; (2) attract, retain and motivate superior talent; and (3) provide a direct link between pay and performance. The Company targets base salaries at the median of the market and overall compensation levels that are competitive within the market.

Q. 64 What is the amount of employee compensation included in the Company's requested cost of service?

A. 64 The Company is requesting recovery for its employee compensation programs, including:

- 100% of base salaries
- 100% of the costs related to the Management Incentive Plan (MIP), net of the MIP costs associated with awards payable to the Corporate Strategy Executives[4] whose MIP awards[5].
- 100% of the Restricted Stock Unit Plan (RSUP) costs, except for the RSUP costs associated with awards payable to Corporate Strategy Executives whose RSUP awards include a component from Centuri.[6]
- 100% of the Company's costs relating to the Supplemental Executive Retirement Plan (SERP).
- 100% of the Company's costs relating to the Executive Deferral Plan (EDP).

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[4] "Corporate Strategy Executives" collectively refers to_the Company's: (a) President and Chief Executive Officer; (b) Senior Vice President, Chief Financial Officer; (c) Executive Vice President, Chief Legal/Administrative Officer and Corporate Secretary; and (d) Vice President of Corporate Strategy & Corporate Development. Southwest Gas is not seeking to recover the portion of the MIP awards payable to the Company's Corporate Strategy Executives that are allocable to the performance of Centuri.

[5] The Company removed $343,192 of test year MIP and RSUP costs related to the Corporate Strategy Executives in Adjustment No. 5. The amount after allocation to Arizona is $182,480.

[6] Ibid.

Q. 65 Why are these costs reasonable to include in the Company's cost of service?

A. 65 Employee compensation, including at-risk variable compensation, such as the MIP, RSUP, SERP and EDP, is a key component of the Company's compensation and benefits package necessary and reasonable to attract and retain qualified employees who continue to deliver superior results for the Company's customers, and provide a direct link between pay and performance. At-risk variable compensation should be treated the same as labor expense, which the Commission considers an appropriate cost of service. Accordingly, the Company is requesting 100% of the costs for employee compensation, with the exceptions for Corporate Strategy Executives noted above.

Q. 66 Please describe the MIP.

A. 66 The MIP is an annual incentive program that provides Executives and certain employees with an opportunity to earn variable, at-risk pay based upon the achievement of specific benchmarks that are critical to the short-term and long-term success of the Company and that reward superior performance for the Company's customers. For each participating Executive and employee (other than the Company's Corporate Strategy Executives) the MIP includes the following five performance metrics: (i) Customer Satisfaction; (ii) O&M Expense per Customer; (iii) Safety – Damage per 1,000 tickets; (iv) Safety – Incident Response Time within 30 minutes; and (v) Net Income. For each metric, the actual performance may vary from 70% to 140% of the target incentive opportunity based on performance relative to the target. No MIP award is paid unless the Company achieves a minimum 80% of the Company's targeted earnings for the performance year.

Q. 67 How are the MIP performance metrics designed?

A. 67 The five MIP performance metrics are designed to reward participants for the following:

- Customer Satisfaction (20% of target MIP weighting) - Designed to reward success in achieving a predetermined customer satisfaction percentage.
- Safety – Damage per 1,000 Tickets (10% of target MIP weighting) - Designed to reward success in minimizing damages per 1,000 tickets
- Safety – Incident Response Time within 30 Minutes (10% of target MIP weighting) - Designed to reward improvement on incident response time.
- O&M Per Customer (20% of target MIP weighting) - Designed to reward efficient operations that benefit the Company's customers.
- Net Income (40% of target MIP weighting) - Designed to reward the efficient operation and performance of the entire organization structured under the Holding Company for the Corporate Strategy Executives, and the efficient operation and performance of Southwest Gas (utility segment only) for the remaining participants, which benefits the Company's customers.

The MIP awards for the Corporate Strategy Executives contain a sixth metric for Construction Services, tied to Centuri. As discussed above, the Company is not requesting recovery of this metric in this application.

Q. 68 Are there other design considerations for the MIP?

A 68 Yes. The Net Income metric is calculated on a consolidated basis for the Corporate Strategy Executives; for the remaining participants, Net Income is calculated with respect to the organization's utility segment by backing out Net Income allocable to Centuri. For all participants, the Net Income metric is measured without regard to Company-Owned Life Insurance (COLI) returns.

Q. 69 Has the MIP design changed since the Company's last GRC in 2016?

A. 69 Yes. In 2016, when the Company submitted its last GRC application, the MIP included only four performance metrics: (i) Customer Satisfaction; (ii) Customer-to-Employee Ratio; (iii) Operating Costs: and (iv) Return on Equity (ROE). The MIP was also designed to pay 40% in the form of cash and 60% in the form of performance shares that vested over three years. The Company updated the MIP in 2017 to better align the program with those of its peers. As part of that update the Company included the metrics described in Q&A 67 above and eliminated the use performance shares as payment for MIP awards. Now, payment of any earned MIP awards is in the form of cash only. The Company's 2017 MIP amendments also added the threshold "gate" requirement of achieving 80% of Company's targeted earnings for the performance year for any payment to be made under the MIP.

Q. 70 Please describe the RSUP.

A. 70 The RSUP is a long-term incentive plan designed to reward sustained performance over a three-year period with each grant made under the plan. The Company grants two forms of award under the RSUP: (1) Performance Share Units (PSUs); and (2) time-vested Restricted Stock Units (RSUs). Executives are eligible to receive PSU awards and both Executives and Director-level employees are eligible to receive RSU awards. PSU and RSU awards are granted annually under the RSUP.

Q. 71 Has the RSUP design changed since the Company's last GRC in 2016?

A. 71 Yes. Prior to the RSUP design described in Q&A 70 above, the determination of whether to grant an RSUP award each year and the value of RSUP grants was based upon the average MIP payout for the three years immediately preceding the RSUP award determination date. The target RSUP award was set at an average MIP payout percentage of 100%, with a threshold award of 50% of target and maximum award of 150% of target, in each case depending on the average MIP payouts for the last three fiscal years relative to the target payouts under that plan. No RSUP award was granted in a plan year unless the average MIP payout for the prior three years was at or above 90%. Under the current design, as discussed above, the RSUP is not based on the average MIP payout and is better aligned with the long-term incentive design of the Company's peers.

Q. 72 Please describe the components of the Company's Executive retirement benefit programs.

A. 72 The Company maintains two retirement benefit programs available to Executives, the EDP and the SERP, in addition to the Company's broad-based tax-qualified retirement plans.

Q. 73 Please describe the SERP.

A. 73 The Company maintains a tax-qualified defined benefit retirement plan (Retirement Plan), which is available to all Company employees and under which benefits are based on an employee's years of service, up to a maximum of 30 years, and the 12-month average of the employee's highest five consecutive years' salaries, excluding bonuses, within the final 10 years of service. The IRS places a limit on the annual compensation that may be paid under the plan; for 2018, the annual limit was $220,000. The annual limit is adjusted over time to reflect cost-of-living increases established by the Internal Revenue Service (IRS).

The SERP is designed to supplement the Retirement Plan for participating Executives by providing an opportunity for Executives to receive a comparable retirement benefit at a level of 50% to 60% of base salary without regard to the IRS limits that apply to the Retirement Plan.

Q. 74 Please describe the EDP.

A. 74 The Company maintains a tax-qualified defined contribution (401(k)) plan that is available to all employees, the Southwest Gas Corporation Employees' Investment Plan (EIP). The EIP permits participants to contribute between 2 and 60 percent of their base salaries to the plan and receive a corresponding Company matching contribution up to 3.5% of their annual salary. Participant contributions to the EIP are subject to annual Internal Revenue Code (IRC) limits that apply to the plan, which was $18,500 for 2018 plus an additional $6,000 in catch-up contributions for participants age 50 or older. Executives are not eligible to receive Company matching contributions under the EIP.

The EDP provides salary deferral opportunities for Executives by permitting them to defer annually up to 100% of base salary and non-equity incentive compensation. Because Executives do not receive Company matching contributions under the EIP, Southwest Gas provides matching contributions under the EDP that parallel the contributions it makes to other participants under the EIP, which is up to 3.5% of a participating Executive's base salary.

Q. 75 Please describe the purpose of the EDP and SERP.

A. 75 The Company maintains the EDP and SERP to attract and retain qualified executives in a competitive marketplace in which the majority of the Company's peer companies offer executive retirement programs. The EDP and SERP also provide participating Executives with an opportunity to receive retirement benefits that are available to other Company employees under the Retirement Plan and EIP that are not otherwise available to the Executives due to applicable IRC limits. The SERP and EDP therefore help put Executives on par with other Company employees with respect to the level of benefits they receive at retirement. The SERP and EDP also align the Executives' interests with the long-term interests of the Company as general unsecured creditors of the Company with respect to their benefits under those plans.

Q. 76 Should the costs associated with the Company's compensation programs be included in customer rates?

A. 76 Yes. Similar to the inclusion of labor costs in the authorized cost of service, Company should be allowed to recover through customer rates all of its employee compensation costs associated with base salaries, its MIP[7] and RSUP costs, and the costs for its Executive retirement programs (EDP and SERP), as reasonable business expenses.

[7] As noted above Southwest Gas is not seeking to recover the portion of the MIP awards payable to the Company's Corporate Strategy Executives that are allocable to Centuri.

VIII. RATE BASE

Q. 77 Please describe and explain Schedules B-1 and B-2.

A. 77 Schedule B-1 is a high-level summary of the various components that comprise rate base. Rate base is presented on this schedule at original cost, reconstruction cost new, and at fair value. Schedules B-2 shows a summary of original cost gas plant by function, and the Company's pro forma adjustments to rate base, as further described below.

Q. 78 Please describe and explain Southwest Gas' Schedules B-3 and B-4.

A. 78 Schedule B-3 is a summary of the reproduction cost new less depreciation (RCND) study. The schedule contains both the direct and system allocable plant assigned to Arizona. The reproduction cost new data is utilized to develop the FVRB. The detail supporting Schedule B-3 is contained in Schedule B-4 which contains the Handy-Whitman indices that were used to trend original cost plant and deferred taxes to obtain the reproduction cost new data, and the reproduction cost new data by vintage year, by FERC account.

Q. 79 Please describe and explain the other rate base items contained in Southwest Gas' Schedule B-5 and B-6 that use the 13-month average balance rather than the end of test year balance.

A. 79 Schedules B-5 and B-6 contain four items that employ the 13-month average balance method for inclusion in rate base: 1) materials and supplies; 2) prepayments; 3) customer deposits; and 4) customer advances for construction. The use of the 13-month average balance as the method of calculation has been accepted by the Commission in the Company's past several rate cases.

Q. 80 Please describe and explain the items contained in Schedule B-5 and B-6 that do not employ the 13-month average balance method.

A. 80 The cash working capital allowance and the accumulated balance of deferred income taxes do not use the 13-month average balance method of calculation.

The cash working capital allowance in Schedule B-5 was determined through a comprehensive lead/lag study. The Company used the lead/lag study days included in this GRC[8] and applied this information to adjusted test year amounts.

Deferred taxes in Schedule B-6 are based on the recorded balance at the end of the test year for state and federal deferred income taxes in Account 282, the excess accumulated deferred income taxes (EADIT) in Account 254, and the alternative minimum tax in Account 190. The recorded amounts are adjusted as explained further below.

Q. 81 Please explain the revenue requirement impact related to EADIT.

A. 81 The Company is proposing to adjust the revenue requirement by the test period amount of amortization allowed by the IRS for the plant-related protected EADIT and to adjust the revenue requirement to fully amortize the non-plant EADIT over a typical rate case cycle.[9] The EADIT regulatory liability amounts are shown on Schedule B-6, Sheet 5, and the proposed annual EADIT amortization amounts for this GRC cycle are shown on Schedule B-6, Sheet 6.[10] The Company's proposal results in a decrease to the revenue requirement of approximately

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[8] After consulting with Commission Staff, for administrative efficiency, the Company utilized the lag day results from the lead lag study prepared in its recent Nevada general rate case, Docket No. 18-05031, test year ended January 31, 2018 for its Other O&M and Benefits tests. No party in that proceeding proposed any changes to the Company's proposed lag days. The Company calculated lead and lag days with test year ended January 31, 2019 data for the remaining items in its lead lag study.

[9] The Company's proposed rate case cycle is three years.

[10] The amounts are prior to gross-up.

$20.6 million per year.

From a rate base perspective, the EADIT regulatory liability continues to be a rate base reduction, just as when it was a component of Accumulated Deferred Income Taxes. The amount of the regulatory liability will decline as EADIT is returned to customers. As EADIT is amortized, income taxes are reduced in the amount of the annual amortization, while an equal reduction is made to the EADIT regulatory liability.

Q. 82 Is the Company proposing any adjustments to the recorded rate base amounts at January 31, 2019?

A. 82 Yes. The Company is proposing three adjustments to recorded rate base amounts: 1) PTY Plant; 2) Deferred Tax Adjustments; and 3) Company-Owned Vehicles.[11]

Adjustment No. 17 – PTY Plant

Q. 83 Please describe and explain Adjustment No. 17 - PTY Plant.

A. 83 There are two components to the PTY Plant adjustment. The first includes non-revenue producing projects expected to be closed through July 31, 2019 that are used and useful and will be serving customers during the rate effective period. The Company's six-month PTY Plant Adjustment for non-revenue producing plant is consistent with Commission-approved practice in prior GRCs. Non-revenue producing plant represents plant that is constructed to improve service or enhance reliability and safety for existing customers.[12] The Company will not realize any incremental operating revenues from the construction and addition of

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[11] The Company-owned vehicle adjustment is addressed in the operating expenses section in Adjustment No. 6.

[12] In contrast, revenue-producing plant is constructed to serve new customers and is not included in the PTY Plant Adjustment.

this plant at the time it is placed into service; in other words, these capital additions are non-revenue producing. Examples of PTY plant in this adjustment include but are not limited to: pipe replacements including replacements under the Company's integrity management programs, franchise-related replacements, pressure reinforcements, measuring and regulating station equipment, intangible and general plant.[13]

The second component of this adjustment addresses System Allocable Miscellaneous Intangible Plant Account 303, as described above in Q&A 51. To match the portion of Adjustment No. 13 which removed the items with amortizations expiring on or before December 31, 2019, this adjustment addresses the additions that are expected to occur during this same timeframe. These adjustments are consistent with prior GRCs.

Q. 84 What is the total impact of the PTY Plant Adjustment on rate base?

A. 84 This adjustment increases rate base by $138,930,605.

Adjustment No. 18 – LNG Storage Facility

Q. 85 Please describe and explain Adjustment No. 18 - LNG.

A. 85 On January 27, 2014, Southwest Gas filed an application for Commission pre-approval to construct a LNG storage facility near Tucson, Arizona (LNG Application), pursuant to the Commission's December 18, 2003 Policy Statement Regarding Natural Gas Infrastructure. The Company's LNG Application was approved in D.74875, as amended in D.75860. In D.76069, the Company was authorized to extend the deferral of the revenue requirement associated with all

[13] The PTY Plant Adjustment does not include plant additions related to the Company's Customer-Owned Yard Line Program (COYL), Vintage Steel Pipe Program (VSP), or the LNG Facility. The LNG Facility is separately addressed in Adjustment No. 18. The Company is proposing that COYL and VSP plant additions after the end of the test year be recovered through those respective infrastructure cost recovery mechanisms.

costs flowing from the construction of the LNG storage facility incurred before December 31, 2020.

The LNG storage facility is anticipated to be placed into service during the third quarter of 2019. Since the Company filed its GRC before that date, the Company has not yet booked any deferrals associated with the LNG storage facility. The Company is proposing to include the capital investment and annualized O&M related to the LNG storage facility for recovery in this GRC in order to minimize deferrals into the regulatory asset requested in the LNG Application. Since the Company's estimated amounts can be reviewed by intervening parties, the plant is non-revenue producing plant, and the adjustment is consistent with PTY adjustments in prior rate cases, the Company believes it is just and reasonable to include the costs related to constructing, operating and maintaining the LNG storage facility as a PTY adjustment. This adjustment increases rate base by $79,000,000 and operating expenses by $1,470,088.

Q. 86 Does the adjustment for the LNG storage facility adhere to the matching principle?

A. 86 Yes. The LNG storage facility is non-revenue producing plant, and the annualized O&M costs are incremental. The Company's customers at the end of the test year are the primary beneficiaries of this facility will continue to be the primary beneficiaries during the rate effective period. Consequently, the inclusion of the LNG storage facility in its revenue requirement more accurately matches the Company's investment and costs needed to serve the customers on its system at the end of the test year.

Q. 87 The Company requested authorization to establish a regulatory asset to defer the on-going revenue requirement associated with the LNG storage facility. Does the Company plan to make any deferrals into this regulatory asset?

A. 87 Yes. The Company plans to begin deferrals into the regulatory asset beginning the month after the LNG storage facility is placed into service, and to make its last deferral the month that rates from this proceeding are effective. The deferred revenue requirement could be added to the revenue requirement approved in this case, in which case the account could be closed, or carried with interest to the Company's next Arizona GRC for disposition.

Adjustment No. 19 – Deferred Tax Adjustments

Q. 88 Please describe and explain Adjustment No. 19 - Deferred Taxes Adjustments.

A. 88 There are two adjustments to recorded test year deferred tax balances, as summarized on WP B-6. The first adjustment was made to align deferred taxes to recorded plant at the end of the test year. The second adjustment was made to remove the deferred taxes associated with the Company's Employee Vehicle adjustment from rate base.

Q. 89 What is the total impact of the Deferred Taxes adjustment on rate base?

A. 89 This adjustment increases rate base by $1,518,173.

IX. FAIR VALUE RATE OF RETURN REQUESTED BY THE COMPANY FOR THIS GRC AND FOR INCREMENTAL INVESTMENTS BETWEEN GRCS

Q. 90 As stated above, the Company's FVRB is $2,612,828,261. Can you please explain how the FVRB is determined?

A. 90 Yes. As shown on Schedule B-1, Sheet 1 and consistent with prior GRCs, the FVRB was determined by giving equal weight (50/50) to the adjusted original cost rate base (OCRB) of $1,991,543,072 and the RCND rate base of $3,234,113,450 requested for recovery in this GRC.

Q. 91 How is the difference between OCRB and FVRB treated in the Company's proposed fair value rate of return (FVROR)?

A. 91 The difference between the FVRB of $2,612,828,261 and the OCRB of $1,991, 543,072 is $621,285,189 and is referred to as the FVRB increment above OCRB. As discussed further in the prepared direct testimony of Company Witness Theodore K. Wood, the FVRB increment above OCRB becomes part of the fair value capital structure used to determine the FVROR and is priced at 50 percent of the long term real risk-free rate of return as proposed in the prepared direct testimony of Company Witness Robert B. Hevert.

Q. 92 What drives the level of the FVRB increment above OCRB?

A. 92 The primary driver of the FVRB increment above OCRB is the age of the Company's plant. In Schedule B-4, the Company shows its RCN calculations. Below is an excerpt from the RCN calculations for steel mains in Account 376:

Vintage	Ratio to Current Index	Original Cost	RCN Cost
1941	43.00	26,467	1,138,081
2019	1.00	4,538,687	4,538,687

Clearly, older plant has a substantial impact on the FVRB increment above OCRB. In the above example, the cost to reconstruct 1941 vintage steel mains is 43 times greater than its original cost. On the other hand, steel mains installed at the end of the test year have no impact on the FVRB increment above OCRB since original cost equals the cost to reconstruct it, and averaging OCRB and RCN to calculate FVRB would also be $4,538,687. This concept is confirmed in the Incremental Fair Value Rate Base section in Table 2 of Mr. Wood's testimony.

Q. 93 If the Commission authorizes a different rate base than was proposed by the Company, does this impact the FVROR proposed by the Company, all else being equal?

A. 93 Yes. Any changes to the Company's rate base request will necessitate a recalculation of the FVRB increment above OCRB, and in turn the fair value capital structure and the FVROR. Ultimately, the FVROR authorized in this GRC will be based solely on the portfolio of plant that is approved by the Commission in this GRC.

Q. 94 Given that any changes to the Company's rate base request will necessitate a recalculation of the FVROR, does it make sense that a revenue requirement calculation on investments added between GRCs (i.e. incremental investment) would be based on the authorized FVROR?

A. 94 No. The Arizona Constitution requires that the Commission establish just and reasonable rates using the fair value of the Company's **property**, not the fair value rate of return that was authorized in the utility's last GRC. If the fair value of incremental investments between rate cases are close to or equal to the original cost of those incremental investments, there is little to no additional FVRB increment above OCRB. Therefore, applying the authorized FVROR to calculate the revenue requirement on incremental investment results in unjust and unreasonable rates, since the authorized FVROR is based on the portfolio of plant included in the GRC which included a substantial FVRB increment above OCRB, and did not include the fair value of the Company's property related to the incremental investment. In other words, the incremental investment has little to no FVRB increment above OCRB, and was not included in the Company's last GRC.

Q. 95 Did the Company provide a reasonableness-check to the conclusion that using the authorized FVROR to calculate the revenue requirement on incremental investment between GRCs would result in unjust and unreasonable rates?

A. 95 Yes. In Table 2 of Mr. Wood's testimony, he demonstrates that for an incremental investment of $100 million, the incremental FVROR is equal to the weighted average cost of capital (WACC) in the year of installation. As a point of reference, the WACC proposed in this GRC is 7.64 percent, while the FVROR proposed in this GRC is 5.98 percent. To summarize, in calculating the revenue requirement on incremental investment between GRCs, using the incremental FVROR would result in just and reasonable rates, using the WACC would result in just and reasonable rates, and using the authorized FVROR would result in unjust and unreasonable rates. Table 3 of Mr. Wood's testimony shows that there is a substantial revenue deficiency that results from using the authorized FVROR rather than the incremental FVROR on incremental investment, again providing support that using the authorized FVROR on incremental investment would result in unjust and unreasonable rates.

Q. 96 Does the Company have a preference as to whether the WACC or the incremental FVROR is used to calculate the revenue requirement on incremental investment?

A. 96 No, both the WACC and the incremental FVROR produce similar results for the revenue requirement calculation on incremental investment. However, after the year of installation, the incremental FVROR starts to deviate slightly from the WACC, since the RCN on the incremental plant generally changes a bit each year as compared to the OCRB. As such, while using the WACC would result in just and reasonable rates, the incremental FVROR on incremental plant is the most accurate methodology to employ to calculate the appropriate revenue requirement on incremental investment between GRCs, and results in just and reasonable rates.

Q. 97 Does this conclude your prepared direct testimony?

A. 97 Yes.

SUMMARY OF QUALIFICATIONS
RANDI L. CUNNINGHAM

I graduated from the University of Washington in Seattle, Washington with a Bachelor of Arts in Business Administration, Accounting. My areas of concentration were accounting and finance. I graduated from the University of Nevada, Las Vegas with a Masters in Business Administration (MBA), with Beta Gamma Sigma honors. I am a Certified Management Accountant (CMA) and a member of the Institute of Management Accountants.

One year before completing my bachelor's degree, I accepted employment at Washington Mutual Savings Bank in Seattle, Washington as an Asset/Liability Management intern. Upon graduation in 1993, I accepted a full-time position as a Financial Analyst Trainee in the Financial Forecasting Department. In 1994, I was promoted to Financial Analyst I. My responsibilities included assisting in the budget and forecasting process and various financial analyses.

In February 1995, I accepted a position as a Budget Analyst in the Budget and Forecasting Department at PriMerit Bank in Las Vegas, Nevada, which was a subsidiary of Southwest Gas at the time. In April 1996, I transferred to Southwest Gas as a Corporate Accountant I in the Accounting Control Department. In January 1998, I was promoted to Analyst I/Accounting. In February 1998, I transferred to the Revenue Requirements department as an Analyst. In January 2001 I was promoted to Specialist, in July 2003 I was promoted to Senior Specialist, in May 2007 I was promoted to Supervisor, and in April 2009 I was promoted to Manager. Subsequent to a reorganization in October 2014, I have worked in the Regulation department in my present position.

I have attended numerous training and technical conferences related to utility ratemaking, regulatory, and accounting issues.

I taught the Cost of Service Problem for "The Basics" conference presented by the Center for Public Utilities at New Mexico State University and the National Association of Regulatory Utility Commissioners from 2003 to 2014.

Tab 9

Direct Testimony of Theodore K. Wood

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-19-0055

PREPARED DIRECT TESTIMONY
OF
THEODORE K. WOOD

ON BEHALF OF
SOUTHWEST GAS CORPORATION

MAY 1, 2019

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of
Prepared Direct Testimony
of
THEODORE K. WOOD

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
THEODORE K. WOOD

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Theodore K. Wood. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest Gas or the Company) in the Financial Services department. My title is Assistant Treasurer & Director/Financial Services.

Q. 3 Please summarize your educational background and relevant business experience.

A. 3 My educational background and relevant business experience are summarized in Appendix A to this testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously provided testimony to the Arizona Corporation Commission (Commission), the Public Utilities Commission of Nevada (PUCN), the California Public Utilities Commission (CPUC)and the Federal Energy Regulatory Commission (FERC).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I sponsor the Company's overall requested rate of return. Specifically, my direct testimony details the requested capital structure and the embedded cost of long-term debt used for determining the appropriate cost of capital for the Company's Arizona rate jurisdiction. In addition, I discuss the importance of the Company's overall rate of return on the Company's bond ratings and financial profile.

Q. 6 Please summarize your prepared direct testimony.

A. 6 My prepared direct testimony consists of the following key issues:

- The development of a Fair Value Rate of Return (FVROR) necessary for the Company to earn a fair return on its Arizona properties;
- A review of the Company's financial profile, addressing the Company's credit ratings and their importance in accessing the capital markets. In doing so, I comment on the impacts to credit ratings due to: (1) the creation of a holding company; (2) tax reform; (3) decoupling; and (4) infrastructure recovery mechanisms. I also comment on the need for Southwest Gas to offer a competitive rate of return to continue to attract capital and discuss why Southwest Gas' requested overall FVROR is necessary to support and sustain the Company's financial profile and credit ratings;
- The Company's requested capital structure for ratemaking, which is composed of 51.10 percent common equity and 48.90 percent long-term debt. The requested capital structure is the Company's actual capital structure for the test period ended January 31, 2019;
- The development of the embedded cost of long-term debt for the Company's Arizona jurisdiction, which is 4.86 percent for the test period ended January 31, 2019; and

- An explanation of why the incremental FVROR is the appropriate rate to be used in conjunction with capital tracker programs, such as the Company's VSP mechanism.

Q. 7 Are you sponsoring any schedules and exhibits in support of your prepared direct testimony?

A. 7 Yes. I sponsor Schedule A-3 and Schedule D-1 through Schedule D-4. In addition, I sponsor Exhibit Nos. ____ (TKW-1) through ____ (TKW-4), which are attached. These schedules and exhibits were prepared by me or under my supervision.

II. SOUTHWEST GAS' FAIR VALUE RATE OF RETURN (FVROR)

Q. 8 Have you determined a reasonable rate of return necessary for Southwest Gas to earn a fair return on its Arizona properties?

A. 8 Yes. An overall FVROR of 5.98 percent for the Arizona jurisdiction is reasonable in this proceeding and properly reflects the Company's level of business, financial, and regulatory risks. The FVROR was developed from the estimated weighted average cost of capital (WACC) for the original cost rate base (OCRB) requested in this proceeding, summarized as follows:

Southwest Gas Corporation

Arizona Rate Jurisdiction

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	48.90%	4.86%	2.38%
Common Equity	51.10%	10.30%	5.26%
Total	100.00%		7.64%

The resulting FVROR to be applied to the fair value rate base (FVRB) is 5.98 percent (the prepared direct testimony of Company witness Robert Hevert details the methodology used to derive the FVROR).

Q. 9 Why is the proposed rate of return appropriate and necessary for Southwest Gas?

A. 9 This rate of return is necessary to maintain the Company's financial integrity, to allow the Company to attract new capital and to permit the Company's equity holders the opportunity to earn a fair and reasonable rate of return (ROR).

Moreover, this rate of return meets the standard of reasonableness established by the United States Supreme Court in Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) (Bluefield):

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

This rate of return also satisfies the comparability standard set by the Court in Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) (Hope):

> . . . the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

An explanation regarding the practical application of these two court rulings to a diversified utility such as Southwest Gas is appropriate.

The Company has, since the late 1950s, filed rate cases as a "diversified" utility. The multi-jurisdictional rate case filings are based on the fact that Southwest Gas, as a natural gas utility, serves three states with several different ratemaking jurisdictions. The Company requests only gas distribution utility required rates of return in all jurisdictional filings within each state. The capital costs requested in this filing are utility-only costs. Southwest Gas' practices assure that the costs of utility operations attributable to each of its jurisdictions are properly insulated from the impact of any non-utility activities.

In summary, Southwest Gas' requested rate of return in this proceeding is fair to both customers and shareholders and properly reflects the risks and returns appropriate for its gas distribution properties.

III. SOUTHWEST GAS' FINANCIAL PROFILE

A. Credit Ratings

Q. 10 What is a credit rating?

A. 10 A credit rating reflects an independent rating agency's opinion of the creditworthiness of a particular company, security, or obligation. Credit ratings play an important role in capital markets by providing an effective and objective tool for market participants to evaluate and assess credit risk. In a report on the role and function of credit rating agencies, the Securities and Exchange Commission (SEC) concluded:

> The importance of credit ratings to investors and other market participants had increased significantly, impacting an issuer's access to and cost of capital, the structure of financial transactions, and the ability of fiduciaries and others to make particular investments.[1]

As a result, the Company's credit ratings are a key factor in determining the

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1 SEC, "Report on the Role and Function of Credit Rating Agencies in the Operation of the Securities Markets," January 24, 2003.

required yield on the Company's debt securities and bank facilities, and the amount and terms of available unsecured trade credit. Credit rating agencies use both quantitative and qualitative information in the process of developing a credit rating.

Q. 11 Is a credit rating the equivalent of an equity rating?

A. 11 No. While both credit and equity analysts use similar analytical tools, a credit rating is quite different from an equity rating as it reflects default risk, which focuses on downside risk. An equity rating looks at both upside and downside risk and is focused on stock price and return performance. The risks faced by debt holders and shareholders are not the same, due to the priority of debt holders on the operating cash flows of a company. Due to differences in risk, debt holders and shareholders have different required rates of return.

Q. 12 How important is the regulatory environment in the determination of a credit rating for a public utility?

A. 12 For a public utility, credit rating agencies regard regulation as a significant factor in determining financial performance, as regulation defines the environment in which the utility operates. The importance of regulation on the credit rating for a utility is reflected in the following statement from Standard & Poor's (S&P):

> Based on Standard & Poor's Ratings Services' experience in rating U.S. investor-owned utilities, we believe that the fundamental regulatory environment can be one of the most important factors we analyze when assigning utility credit ratings.[2]

Similarly, Moody's Investors Service (Moody's) states:

> For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts

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2 Standard & Poor's RatingsDirect, *Credit FAQ: Standard & Poor's Assessments Of Regulatory Climates For U.S Investor-Owned Utilities,* November 25, 2008, p. 2.

to that environment are the most important credit considerations.[3]

The importance of regulation in the ratings process for utilities is further evidenced by Moody's assigning a 50% weighting to the following two key factors: (1) regulatory framework; and (2) the ability to recover costs and earn returns.

Q. 13 What are the Company's current long-term unsecured debt credit ratings?

A. 13 Currently, Southwest Gas' long-term unsecured debt credit ratings are "A" from Fitch, Inc. (Fitch), "A3" from Moody's, and "BBB+" from S&P.

Q. 14 What is the Company's current credit rating outlook?

A. 14 Credit rating agencies also provide credit rating outlooks, which is an assessment of the direction of the credit rating over the intermediate to longer term. The current credit rating outlooks for Southwest Gas provided by Moody's and Fitch are "stable", while the ratings outlook from S&P is "negative". The latest available credit agency reports are included in Exhibit No.__ (TKW-1).

Q. 15 How do the Company's credit ratings compare to the proxy group of companies used to estimate the cost of common equity?

A. 15 The proxy group of seven natural gas local distribution companies used by Company witness Robert Hevert have an average Moody's rating of A1 and an average S&P rating of A-. Relative to Southwest Gas, the proxy group has an average rating from Moody's that is one notch higher (A2 versus A3). Compared

3 Moody's Investors Service, Moody's Rating Methodology, *Regulated Electric and Gas Utilities*, June 2017, p. 6.

to the Company's S&P rating, the proxy group has an average rating that is one notch higher (A- versus BBB+).[4]

B. Holding Company Reorganization

Q. 16 Please discuss the Company's reorganization into a holding company structure.

A. 16 On January 1, 2017, Southwest Gas reorganized and implemented a holding company structure to provide further separation between its regulated and unregulated lines of business, as well as to provide additional financing flexibility. This reorganization was approved by the Commission in Decision No. 75562 (Docket No. G-01551A-15-0351). As part of the holding company reorganization, Centuri Construction Group, Inc. (Centuri) and Southwest Gas each became subsidiaries of the new publicly traded parent holding company, Southwest Gas Holdings, Inc.; whereas, historically, Centuri had been a direct subsidiary of Southwest Gas. All of the Company's outstanding debt securities (not associated with Centuri) at the time of the reorganization remained at the Southwest Gas utility entity. Each outstanding share of Southwest Gas common stock automatically converted into a share of stock in Southwest Gas Holdings, Inc., on a one-for-one basis, and the ticker symbol of the stock, "SWX," remains unchanged.

Q. 17 How have the rating agencies viewed the reorganization?

A. 17 The rating agencies have viewed this as beneficial to the credit rating, with Moody's stating:

> We view this change in organizational structure as credit positive because it provides additional separation between Southwest Gas and Centuri, reducing the likelihood of credit contagion from

4 Prepared Direct Testimony of Company witness Robert B. Hevert, Exhibit No.____(RBH-11).

the unregulated businesses.[5]

C. Tax Reform

Q. 18 What impact does tax reform have on the Company's credit rating?

A. 18 The Tax Cuts and Jobs Act (Tax Act), which was signed into law December 22, 2017 and became effective January 1, 2018, decreased the corporate income tax rate from 35 percent to 21 percent. Given that income taxes are a material portion of the utility's revenue requirement, the reduction in the tax rate has a positive impact on customer rates. Customers are already receiving the benefit of the Tax Act through the Commission's approval of a credit reflecting a $20 million reduction in the Company's authorized cost of service (Decision No. 76798).[6] However, rating agencies have viewed the Tax Act to be credit negative, as it reduces a utility's cash flow. Moody's stated the following:

> Within the investor-owned utilities sector, the just-passed tax legislation will have an overall negative credit impact on regulated operating companies and their holding companies. Although the regulated utility sector is carved out in terms of the treatment of interest deductibility and expensing of capital expenditures, from an earnings perspective, the effect on regulated entities is neutral because savings on the lower tax expense are passed on to their customers as required by regulation. However, from a cash flow perspective, the legislation is credit negative.[7]

Correspondingly, Fitch stated:

> The Tax Cuts and Jobs Act has negative credit implications for the regulated utilities and several utility holding companies over the short to medium term. A reduction in customer bills to reflect lower federal income taxes and return of excess ADIT (Accumulated Deferred Income Taxes) to customers is expected to lower revenues and FFO (Funds from Operations) across the sector. Absent mitigating strategies on the regulatory front, this is

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5 Moody's Investors Service, *Credit Opinion: Southwest Gas Corporation,* January 5, 2018, p.3-4.

6 Please refer to the prepared direct testimony of Company witness Byron C. Williams for additional information on the Tax Act.

7 Moody's Investors Services, *Sector In-Depth: Tax Reform- US, Corporate tax cut is credit positive, while effects of other provisions vary by sector*, December 21, 2017, p.6.

> expected to lead to weaker credit metrics and negative rating actions for those issuers that have limited headroom to absorb the leverage creep. The end of bonus depreciation or the "interest-free loan" from the federal government and reduced FFO at a time when capex budgets are elevated will necessitate greater reliance on equity and debt funding for the utility subsidiaries. This could lead to higher costs of capital for the sector, especially if regulators require an immediate reduction in customer bills to reflect the tax law changes.[8]

In response to the negative cash flow impacts on projected financial metrics, Moody's lowered the ratings outlook on 25 regulated utilities and utility holding companies (24 from stable to negative and one from positive to stable).[9] Neither Southwest Gas or Southwest Gas Holdings, Inc. were among the companies cited in the ratings action by Moody's. However, in June 2018, Moody's announced they changed their outlook for the entire regulated utility sector to negative.[10] As cited by Moody's, the Tax Act has increased the financial risk for utilities. With the Tax Act, the loss of bonus depreciation for utilities beginning in 2018 coupled with a lower tax rate reduces the cash flow contribution from deferred taxes associated with capital investment. Bonus depreciation had generally been available since September 11, 2001 and ranged from 30% to 100%.[11] Moody's also discusses the refunding of excess deferred taxes over the long-term, which will also have a negative cash flow impact. The negative cash flow impacts from the Tax Act will create a more challenging financial environment going forward, which may negatively impact the Company's ability to maintain its current credit ratings.

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8 Fitch Ratings, *Special Report: Tax Reform Impact on the U.S. Utilities, Power & Gas Sector*, January 24, 2018, p.2.

9 Moody's Investors Services, *Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform*, January 19, 2018.

10 Moody's Investors Service, *Regulated utilities – US, 2019 outlook shifts to negative due to weaker cash flows, continued high leverage*, June 18, 2018.

11 Bonus depreciation provision was not in place during the period January 1, 2005 – December 31, 2007.

Q. 19 What can be done to mitigate the negative credit rating impact resulting from the Tax Act?

A. 19 Both regulatory responses and financial policy changes by utilities can help offset the impact to credit metrics. Some of the potential regulatory actions cited by Moody's include:

> Potential regulatory offsets to tax-related cash leakage could include: accelerated cost recovery of certain regulatory assets or future investment; changes to the equity layer or allowed ROEs in rates, and other actions.[12]

From a financial policy perspective, some utilities are increasing the amount of common equity in their capital structures to help improve their credit metrics. For example, due to the Tax Act, several large utilities, including Duke Energy Corporation, Southern Company and Dominion Energy Inc. issued or set-up programs to issue additional equity during the first quarter of 2018 to improve their financial profile.

Q. 20 Has the Company or its parent company, Southwest Gas Holdings, Inc., issued additional common equity to maintain the Company's strong investment grade credit ratings?

A. 20 Yes. Southwest Gas is committed to maintaining an appropriate capital structure to support its strong investment grade credit ratings. This commitment has been demonstrated by the parent company's willingness to continue to issue new equity to finance the Company's investment in utility plant and maintain its capital structure. New equity issuances to support the Southwest Gas capital structure have come primarily from the establishment of a $150 million Equity Shelf

12 Id. at p.1.

Program (ESP).[13] During the period January 2017 through December 2018, the Company issued 1,652,412 shares of common stock under this program, raising net proceeds of approximately $125.7 million. The net proceeds during this period were contributed to, and reflected in the records of, Southwest Gas as a capital contribution from the parent holding company. At December 31, 2018, the Company had approximately $23 million of remaining ESP capacity.

In addition, approximately $29.3 million of capital contributions from parent holding company were made over the same period, using proceeds of common stock issuances from the parent company's other common stock programs and a secondary common stock issuance.

D. <u>Delivery Charge Adjustment (DCA) Mechanism</u>

Q. 21 Has the Company's decoupled rate design been a positive credit rating factor?

A. 21 Yes. The decoupled rate design, or the DCA, has been a positive contributing factor in Southwest Gas' ability to improve its credit ratings in two ways: (1) improved credit metrics due to less volatile cash flows and revenues; and (2) as a sign of increased regulatory support by the Commission.

13 On March 29, 2017, Southwest Gas Holdings, Inc. filed with the Securities and Exchange Commission ("SEC") an automatic shelf registration statement on Form S-3 (File No. 333-217018), which became effective upon filing, for the offer and sale of up to $150 million of common stock from time to time in at-the-market offerings under the prospectus included therein and in accordance with the Sales Agency Agreement, dated March 29, 2017, between the Company and BNY Mellon Capital Markets, LLC (the "Equity Shelf Program"). Sales of the shares will continue to be made at market prices prevailing at the time of sale. Net proceeds from the sale of shares of common stock under the Equity Shelf Program will be used for general corporate purposes, including the acquisition of property for the construction, completion, extension or improvement of pipeline systems and facilities located in and around the communities Southwest Gas serves.

E. <u>Infrastructure Replacement Programs</u>

Q. 22 Please briefly describe the Company's approved Customer Owned Yard Line (COYL) replacement program.

A. 22 In Decision No. 72723 in Southwest Gas' 2010 general rate case, the Commission approved the Company's COYL program (consistent with the terms of a Settlement Agreement involving the Company and various other parties to the docket) to replace all COYLs within the Company's Arizona service territory. Decision No. 72723 also authorized the establishment of the COYL Cost Recovery Mechanism (CCRM). The CCRM is the mechanism that allows Southwest Gas to recover the revenue requirement on the capital investment associated with the COYL program between general rate cases.

In subsequent decisions, the Commission has approved modifications to the COYL program. In January 2014, the Commission issued Decision No. 74304, which modified Decision No. 72723 to create Phase II of the COYL program, which allowed the Company to replace COYLs, regardless of whether they were leaking, in conjunction with the Company's other pipe replacement activity. In April 2017, the Commission issued Decision No. 76069 in the Company's 2016 general rate case, which further expanded the program.

Q. 23 Please briefly describe the Company's Vintage Steel Pipe (VSP) replacement program.

A. 23 In Decision No. 76069 in the Company's 2016 general rate case, the Commission approved the Company's proposed VSP replacement program. The VSP program facilitates the accelerated replacement of pre-1970's VSP in the Company's Arizona service territory. The Commission approved an annual VSP surcharge to collect the revenue requirement associated with VSP replacements not yet recognized in authorized rate base.

Q. 24 Please briefly describe the Company's proposed 7000/8000 Replacement Program.

A. 24 In this proceeding, the Company is proposing a new program to facilitate the replacement of non-conforming M7000/8000 pipe. The specific details of the Company's proposed replacement program and its proposed cost recovery mechanism are described in the prepared direct testimonies of Company witnesses Kevin M. Lang and Matthew D. Derr, respectively.

Q. 25 How have the COYL and VSP replacement programs helped to sustain the Company's financial profile?

A. 25 The COYL and VSP replacement programs have improved the Company's ability to recover costs associated with non-revenue producing pipe replacement on a more-timely basis. Over time, this helps to maintain Southwest Gas' financial metrics, including its ability to earn its authorized rate of return (ROR), and increases the likelihood for Southwest Gas to maintain its credit ratings. From a capital attraction standpoint, the COYL and VSP mechanisms make Southwest Gas more comparable to other natural gas utilities with similar mechanisms that allow for timely recovery of infrastructure replacement costs. As reported by Company witness Robert Hevert, substantially all the proxy group companies used to estimate the cost of common equity in this proceeding have infrastructure recovery mechanisms.[14]

14 Prepared Direct Testimony of Company Witness Robert Hevert, p.49.

Q. 26 How do rating agencies view capital tracking mechanisms such as COYL and VSP as a factor for the Company's credit rating?

A. 26 Rating agencies view the Commission approval of such mechanisms as a positive regulatory support factor. Specifically, rating agencies recognize the benefit from such mechanisms, with S&P stating:

> A utility's credit quality during construction projects will depend on credit-supportive regulation. We believe supportive and timely cost recovery that helps avoid large rate increases will become more critical to utilities' ability to maintain cash flow, earnings power, and, ultimately, credit quality. Cost recovery options generally include base-rate increases when projects are complete, along with rate surcharges and riders during construction.[15]

Similarly, Moody's states:

> An increasing array of accelerated cost recovery mechanisms in various state jurisdictions is helping to support the credit qualities of gas utilities.[16]

In addition, Moody's has specifically cited the approval of such infrastructure recovery mechanisms for Southwest Gas as reflecting constructive regulatory treatment and being credit positive, stating:

> In recent years, there have been meaningful improvements in the regulatory frameworks under which Southwest Gas operates. For example, infrastructure tracker mechanisms were approved in Arizona and Nevada. In Arizona and more recently in California, Southwest Gas was granted a Customer-Owned Yard line program (COYL), and an Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM) for timely cost recovery of qualifying non-revenue producing capital expenditures associated with the enhancement and replacement of gas infrastructure. A gas infrastructure recovery (GIR) mechanism has been implemented in Nevada with the 2014 GIR advance application authorizing $14.4 million of replacement work for 2015. Also, all three

15 Standard & Poor's RatingsDirect, U.S. Utilities' Capital Spending Is Rising, And Cost Recovery Is Vital, May 14, 2012.

16 Moody's Investors Service, Special Comment, *Pipeline Safety Costs Rising As Alternative Rate Designs Sought*, April 25, 2012, p. 1.

> jurisdictions implemented decoupling mechanisms albeit the actual mechanism varies state by state. Constructive regulatory framework developments and signs of an improving regulatory environment are credit positive.[17]

Q. 27 Are there any aspects of the VSP mechanism that hinder its effectiveness in being a constructive credit supporting regulatory mechanism?

A. 27 Yes. As currently implemented, the VSP mechanism provides for only a partial recovery of the Company's capital costs due to the method used to develop the FVROR for the mechanism. Section VI of my testimony addresses this issue in further detail and provides evidence on how the appropriate FVROR should be developed for the VSP mechanism. The methodology proposed would be the appropriate methodology for any other mechanisms used by utilities in Arizona to recover capital costs for incremental investment in utility plant, as it is both consistent with the FVRB requirement and with the general rate case process.

Q. 28 Please summarize the importance of the potential credit rating impacts resulting from this proceeding to Southwest Gas.

A. 28 The potential impacts of this proceeding on the Company's credit rating are of significant importance due to the capital-intensive nature of the natural gas distribution business. Southwest Gas must make continuing and substantial investments to provide safe and reliable service to its customers. On a total company basis, Southwest Gas anticipates capital expenditures over the next three-year period ending December 31, 2021, of approximately $2.1 billion.

17 Moody's Investors Service, *Credit Opinion: Southwest Gas Corporation,* March 24, 2015, p.2

Of this amount, just over $1 billion is projected to be invested in the Company's Arizona service territory. Accordingly, Southwest Gas needs to have continuing access to capital and credit capacity at reasonable costs. Approval of the Company's requested FVROR will provide the Company the opportunity to sustain its credit ratings, which benefits both its customers and its investors.

F. <u>Capital Attraction</u>

Q. 29 Given the Company's operating environment, what are the key factors that will enable the Company to continue to attract the capital necessary to meet its ongoing capital requirements?

A. 29 Generally, investors will choose between investment alternatives based on the risk and reward characteristics of the available investment opportunities. Consequently, the Company must compete with other utilities and other investment opportunities in fully competitive global capital markets to attract equity capital. For Southwest Gas to successfully attract equity capital, it must demonstrate an ability to achieve a competitive return on that equity capital. The ongoing and repeated need to access the capital markets for equity is not just an academic discussion. As previously discussed, $125.7 million of common stock has been issued through the parent company's ESP and pushed down as equity to Southwest Gas. The prepared direct testimony of Company witness Robert B. Hevert discusses the development of a fair and reasonable cost of common equity of 10.30 percent, considering the Company's specific risk factors and costs of common equity for proxy groups of similar natural gas utilities.

Q. 30 How does the overall FVROR balance the interests of both customers and investors of the Company?

A. 30 The Company's financial health is, over time, important in determining the rates it must charge its customers. The Company's credit ratings are significantly influenced by its financial strength. The Company's cost of debt is in large part determined by the Company's credit ratings. All other things being equal, with higher credit ratings, the Company's cost of capital and the rates it charges its customers would be lower.

It is also important that investors be given the opportunity to earn an ROR commensurate with the level of risk associated with their investment. Investor confidence in Southwest Gas, which is the primary subsidiary of Southwest Gas Holdings, is important for the parent company's existing shareholders and for its future ability to issue additional common equity. If the overall authorized ROR is set below the Company's actual cost of capital, the Company may be unable to attract sufficient financing at reasonable rates to continue to fund required capital expenditures and maintain its quality of customer service. The Company's requested overall FVROR will help sustain the Company's financial condition, including its credit ratings. In the long-run, this will benefit both the Company's customers and investors.

In summary, the improved regulatory environment in Arizona has been recognized as a key factor for the improved financial profiles for the state's utilities.[18] With the constructive regulatory support of the Commission in approving the Company's proposed overall FVROR, Southwest Gas can

18 FitchRatings, *Special Report: Arizona Regulation: Improved Regulatory Compact*, January 7, 2016.

continue to sustain the progress it has made in improving its financial profile and credit ratings. Such improvement has and will continue to benefit Southwest Gas' customers by minimizing the long-run average capital costs embedded in customer rates.

IV. RECOMMENDED CAPITAL STRUCTURE

Q. 31 What is current Commission-authorized ratemaking capital structure and overall ROR for Southwest Gas?

A. 31 In the Company's last general rate case (Decision No. 76069 in Docket No. G-01551A-16-0107), the Commission adopted the following capital structure, capital costs and overall ROR:

Southwest Gas Corporation
ACC Authorized Rate of Return
Decision No. 76069

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	48.30%	5.20%	2.51%
Common Equity	51.70%	9.50%	4.91%
Total	100.00%		7.42%

The authorized FVROR on FVRB was 5.71 percent, with a cost rate of 0.93 percent on the FVRB increment.

Q. 32 What is the Company's recommended capital structure for ratemaking purposes in this proceeding?

A. 32 The Company requests a capital structure at the end of the test period, January 31, 2019, composed of 51.10 percent common equity and 48.90 percent long-term debt. The requested capital structure is comparable to the Company's currently authorized capital structure.

Q. 33 What type of capital structure is used by the Commission for ratemaking purposes?

A. 33 For ratemaking purposes, the Commission's longstanding practice has been to utilize capital structures based upon permanent capital, which excludes short-term debt, as permanent capital is the capital used to finance the long-term rate base investment of a utility. The rationale for this practice is that utilities generally use short-term debt to finance working capital requirements, including deferred energy balances, and to finance construction work in progress. Short-term debt that is used to finance a utility's working capital requirements and deferred energy receivable balances should not be included in setting an allowed rate of return, as this would lead to an incorrect estimate of the true cost of financing a utility's long-term rate base assets. Support for using the permanent capital structure for ratemaking purposes can be found in Decision No. 57075 (August 1990), lines 5-9, page 67, where the Commission discussed the appropriate capital structure for Southwest Gas:

> It properly excludes short-term debt from the capital structure in accordance with prior decisions. See e.g., APS, Decision Nos. 53761 (date), 55228 (October 9,1986) 55931 (April 1, 1988); and Mountain States Telephone and Telegraph Company, Decision No. 53849 (December 22, 1983).

Southwest Gas has consistently excluded short-term debt from its Arizona general rate case filings and the Commission has consistently accepted that practice.

Q. 34 How does the recommended capital structure compare to the average of the proxy group companies used to estimate the cost of common equity?

A. 34 Southwest Gas' recommended capital structure compares to the proxy group of seven local distribution companies (LDC) as follows:[19]

Capital Structure Ratios

Type of Capital	Southwest Gas Requested	Proxy Group 3-Year Average[1]
Long-Term Debt	48.9%	43.8%
Common Equity	51.1%	56.2%
Total Capital	100.0%	100.0%

Southwest Gas' requested ratemaking capital structure contains more leverage when compared to the average permanent capital structure of the proxy group of LDCs included in this table.

V. EMBEDDED COST OF LONG-TERM DEBT

Q. 35 Have you determined the test period embedded cost rate for long-term debt capital?

A. 35 Yes. Southwest Gas' cost rate for long-term debt is 4.86 percent for the test period ended January 31, 2019. This rate is summarized on line 1, column (c), of Schedule D-1, Sheet 1 of 2. Schedule D-2, Sheets 1 through 4, contains the development of the long-term debt cost rate. The cost of debt is comprised of the cost of fixed-rate debentures and notes, fixed-rate medium-term notes, and

19 3-year (2016-2018) average permanent capital structure of a proxy group of seven local gas distribution companies included in Company witness Robert Hevert's testimony. See Exhibit No.___(TKW-2), Sheet 1 of 8.

a variable-rate term facility.

Q. 36 Please describe the development of the cost rates of the debentures and notes.

A. 36 The Company had seven outstanding debentures and notes, totaling $1.425 billion of gross principal, at the end of the test year. The debentures and notes had a weighted average cost of 4.86 percent, as shown on line 8, column (e), of Schedule D-2, Sheet 2 of 6.

Q. 37 Please describe the cost rate of the medium-term notes.

A. 37 The Company established a $150 million medium-term note program in November 1997. The name is somewhat of a misnomer as medium-term notes can be issued with maturities ranging from nine months to 30 years. The Company issued its entire medium-term note program and had three outstanding medium-term note issues totaling $57.5 million of gross principal at January 31, 2019. The medium-term notes had a weighted average cost of 7.78 percent, as shown on line 12, column (e), of Schedule D-2, Sheet 2 of 6.

Q. 38 How are the effective cost rates of debentures, notes, and medium-term notes calculated?

A. 38 The effective cost rates of debentures, notes, and medium-term notes are calculated through the use of the yield-to-maturity (YTM) or the effective interest rate method.

Q. 39 Please describe and discuss the cost of the unamortized loss on reacquired debt.

A. 39 In March 2010, the Company redeemed at par $100 million in Trust Originated Preferred Securities (TOPrS), which had an effective cost of 8.20 percent. The redemption expenses and the remaining unamortized balance are being amortized on a straight-line basis to the original maturity date of the called TOPrS, which is September 2043.

The effective cost for the unamortized loss on reacquired debt is calculated by dividing the annual amortization, $171,862 by the remaining recorded amount, $(4,239,257) as shown on line 13, column (f) and column (d), of Schedule D-2, Sheet 2 of 6.

Q. 40 Please describe and discuss the development of the cost rate for the variable-rate term facility debt.

A. 40 The Company has a $400 million revolving credit facility, which is scheduled to expire in March 2022. In addition, the Company has a $50 million uncommitted F-2 commercial paper program, supported by the revolving credit facility. The Company continues to view $150 million of the facility as a permanent intermediate-term component of its debt portfolio. Accordingly, the Company has classified it as long-term debt. Southwest Gas views the remaining $250 million of the facility to fund recurring seasonal working capital needs.

At the end of the test period, the Company had $100 million outstanding in LIBOR based loans and $50 million outstanding in commercial paper. The all-in effective rate of the long-term debt portion of the facility at the end of the test period was 3.50 percent as shown on line 1, column (e), of Schedule D-2, Sheet 3 of 6. The all-in rate effective rate includes the interest on the loans and discount on commercial paper, an annual fee, the unused commitment fees for amounts outstanding as commercial paper, and amortization of debt expenses incurred to establish the term facility.

Q. 41 Why are the Industrial Development Revenue Bonds (IDRBs) excluded in calculating the cost of long-term debt?

A. 41 Southwest Gas issued IDRBs in two Non-Arizona rate jurisdictions – Clark County, Nevada and Big Bear, California. The IDRB issues outstanding at the end of the test period are as follows: (1) the Clark County, Nevada IDRBs (2003 Series A, 2008 Series A and 2009 Series A) for the Company's Southern Nevada rate jurisdiction; and (2) the City of Big Bear, California IDRBs (1993 Series A) for its Southern California rate jurisdiction. As reflected in the IDRB indentures and financing agreements, the proceeds from the issuance of this type of debt are restricted to funding qualified construction expenditures for additions and improvements in the specific distribution systems to which the IDRBs relate. In addition, there are strict Internal Revenue Service (IRS) rules which mandate that the benefits of the tax-exempt, lower cost IDRBs must accrue to customers in the specific jurisdiction to which the IDRBs apply. Deviation from the requirements of this IRS ruling could result in the loss of the IDRB tax-exempt status which would, in turn, cause the Company to refinance its debt at a higher cost.

Q. 42 How have this and other regulatory commissions treated the cost of Southwest Gas' IDRBs in past regulatory proceedings?

A. 42 Southwest Gas has historically excluded the IDRBs from the cost of debt calculation in all regulatory jurisdictions, except for the specific jurisdictions (Southern Nevada for Clark County IDRBs and Southern California for City of Big Bear IDRBs), to which the relevant IDRBs apply. This Commission, the PUCN, the CPUC, and the FERC have accepted this treatment for IDRBs in past regulatory proceedings.

VI. INCREMENTAL FVROR AS APPROPRIATE RATE OF RETURN FOR CAPITAL TRACKER PROGRAMS

Q. 43 Please discuss the appropriate FVROR to be used with Capital Tracker Programs.

A. 43 The current methodologies utilized for the FVROR were established in the remand proceeding for Chaparral City Water Company in Decision No. 70441 (Docket No. W-02113A-04-0616). The complexity increases when developing the appropriate FVROR to be applied to new investments in rate base between general rate cases, which are under a capital cost recovery or tracking mechanism, such as the VSP. In prior cases in Arizona concerning other utilities, the Commission has used the FVROR established in the general rate case.[20]

Simply using the FVROR established in the general rate case is problematic as it does not take into consideration the dynamic nature of the FVROR, which changes as the age of the portfolio of utility investments changes. As a result, applying the FVROR from the general rate case to new incremental investments in rate base will always result in an under recovery of capital costs and generate a revenue deficiency - and it therefore does not result in just and reasonable rates on the fair value of the property recovered through the capital cost recovery or tracking mechanism. The FVROR determined in a general rate case, which is applied to the authorized FVRB that is a multiple of authorized OCRB, is generally significantly below a utility's marginal cost of capital. However, it still provides the opportunity to recover its capital costs given

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20 Docket No. E-01345A-16-0036, *Arizona Public Service Company's Request for Approval of a Selective Catalytic Reduction Adjustment.*

that it is applied to a rate base greater than the OCRB. For incremental new investments in rate base, by definition, the OCRB and FVRB should be the same in year 1 – but could change each year subsequent. Therefore, using the FVROR established in a general rate case will not yield a revenue requirement on incremental plant to cover a utility's cost of capital. This result is inconsistent with both the theories of finance and Decision No. 70441.

The appropriate methodology that is consistent and equivalent with the general rate case process, is to compute the incremental FVROR for the incremental investments recovered under a capital cost recovery or tracking mechanism. Holding all else constant, the cost of capital revenue requirement for incremental investments should be the same if established by a tracking mechanism or if established in a general rate case, which can only be accomplished by computing and utilizing the incremental FVROR for such investments. This methodology provides a utility the opportunity to recover its capital costs and results in just and reasonable rates.

Q. 44 Can you illustrate the use of the incremental FVROR?

A. 44 Yes. We can use an example to demonstrate how using the incremental FVROR is appropriate, as it is consistent and equivalent with that of the general rate case process. First, it is necessary to: (1) define the FVRB and reproduction cost new depreciated (RCND) rate bases; (2) understand how the FVRB is computed; and (3) how it impacts the development of the FVROR. The term FVRB for ratemaking purposes is defined as being somewhere between the OCRB and the RCND rate base.[21] In Arizona, the standard convention for computing the

21 See Charles F. Phillips, Jr., *The Regulation of Public Utilities - Theory and Practice* 358 (Public Utilities Reports, Inc., 2d ed. 1988, Chapter 8, for the historical evolution of the FVRB concept.

FVRB has been based on a simple 50/50 weighted average of the OCRB and RCND rate base. The RCND rate base is computed by using the Handy-Whitman utility construction indices to trend original cost utility plant and certain other rate base items to obtain the current reproduction cost new, by vintage year of construction. The difference between the OCRB and the computed FVRB will be a function of the age of the utility plant, where a utility with a greater average utility plant age will result in a greater difference between the OCRB and FVRB. The Commission, in Decision No. 70441, concluded that the weighted average cost of capital (WACC) was related to the OCRB and that an adjustment to the WACC was appropriate in determining a rate of return on the FVRB. To compute the FVROR, first the WACC is assigned to the OCRB portion of the FVRB and then second, a rate of return is assigned to the fair value increment above the OCRB (Fair Value Increment = FVRB-OCRB) to compute the FVROR. The cost factor assigned to the fair value increment above OCRB has been standardized to be 50% of the long-term real risk-free rate of return. The real return, as opposed to a nominal rate of return, is used to prevent double counting of the inflation embedded in the FVRB.

Using the underlying data and resulting FVRB and FVROR approved in the Company's last general rate case, Decision No. 76069, the underlying WACC and the resulting FVROR are displayed in the following table:

Authorized Fair Value Rate Base	Amount			
Original Cost Rate Base (OCRB)	$ 1,324,902,393			
Reconstruction Cost New Depreciated (RCND)	2,277,227,765			
Fair Value Rate Base (FVRB)	$ 1,801,065,079 [1]			
FVRB/OCRB Multiple	1.36			
Capital Structure OCRB-WACC	Amount	Ratio	Cost	ROR
Common Equity	$ 684,974,537	51.70%	9.50%	4.91%
Long-Term Debt	639,927,856	48.30%	5.20%	2.51%
Total Capital	$ 1,324,902,393	100.00%		7.42%
Authorized Fair Value Rate of Return (FVROR)	Amount	Ratio	Cost	FVROR
Common Equity	$ 684,974,537	38.03%	9.50%	3.61%
Long-Term Debt	639,927,856	35.53%	5.20%	1.85%
FVRB Increment Above OCRB	476,162,686	26.44%	0.93%	0.25%
Total Capital	$ 1,801,065,079	100.00%		5.71%

Notes:
[1] FVRB = 0.5 X OCRB + 0.5 X RCND

Table 1. Authorized FVRB and FVROR (Decision No. 76069)

For example, assume the Company invested $100,000,000 in new incremental OCRB under the VSP program. At the time of the new investment in utility plant, the OCRB for this plant will be equivalent to the RCND rate base for that plant and therefore, by definition, will also be equal to the FVRB for that plant. The incremental FVROR would be computed as follows:

Incremental Fair Value Rate Base					
		Amount			
Original Cost Rate Base (OCRB)	$	100,000,000			
Reconstruction Cost New Depreciated (RCND)		100,000,000			
Fair Value Rate Base (FVRB)	$	100,000,000 [1]			
FVRB/OCRB Multiple		1.00			

Capital Structure OCRB-WACC		Amount	Ratio	Cost	ROR
Common Equity	$	51,700,000	51.70%	9.50%	4.91%
Long-Term Debt		48,300,000	48.30%	5.20%	2.51%
Total Capital	$	100,000,000	100.00%		7.42%

Incremental Fair Value Rate of Return (FVROR)		Amount	Ratio	Cost	FVROR
Common Equity	$	51,700,000	51.70%	9.50%	4.91%
Long-Term Debt		48,300,000	48.30%	5.20%	2.51%
FVRB Increment Above OCRB		-	0.00%	0.93%	0.00%
Total Capital	$	100,000,000	100.00%		7.42%

Notes:
[1] FVRB = 0.5 X OCRB + 0.5 X RCND

Table 2. Incremental FVRB and FVROR - $100 Million Investment

Under this scenario, since the FVRB is equal to the OCRB, the incremental FVROR is equal to the WACC on the OCRB, as reflected in Table 2.

Q. 45 Please demonstrate the under recovery that would occur if the FVROR authorized in the general rate were applied to the incremental FVRB for investments as compared to using the incremental FVROR.

A. 45 As reflected in the Table 3, utilizing the incremental FVROR of 7.42% provides the Company an opportunity to earn the authorized ROE of 9.50% for the incremental investment. Using the FVROR from the general rate case provides the Company an ROE of 6.67%, which 283 basis point below the authorized ROE of 9.50%. On a revenue basis, using the general rate case FVROR generates a deficiency of 22.6%; therefore, its use allows for only a partial recovery of capital costs of approximately 77.4%.

	Incremental FVROR	GRC FVROR	% Deficiency
Fair Value Rate Base	$ 100,000,000	$ 100,000,000	
FVROR	7.42%	5.71%	
Pretax FVROR	10.48%	8.11%	
Revenue	$ 10,481,000	$ 8,109,002	22.63%
Interest Expense	2,511,600	2,511,600	
Pretax Income	$ 7,969,400	$ 5,597,402	
Income Taxes @ 38.37%	3,057,780	2,147,668	
Net Income	$ 4,911,620	$ 3,449,734	29.76%
Common Equity	$ 51,700,000	$ 51,700,000	
ROE	9.50%	6.67%	

Table 3. Results of Incremental FVROR and Authorized FVROR

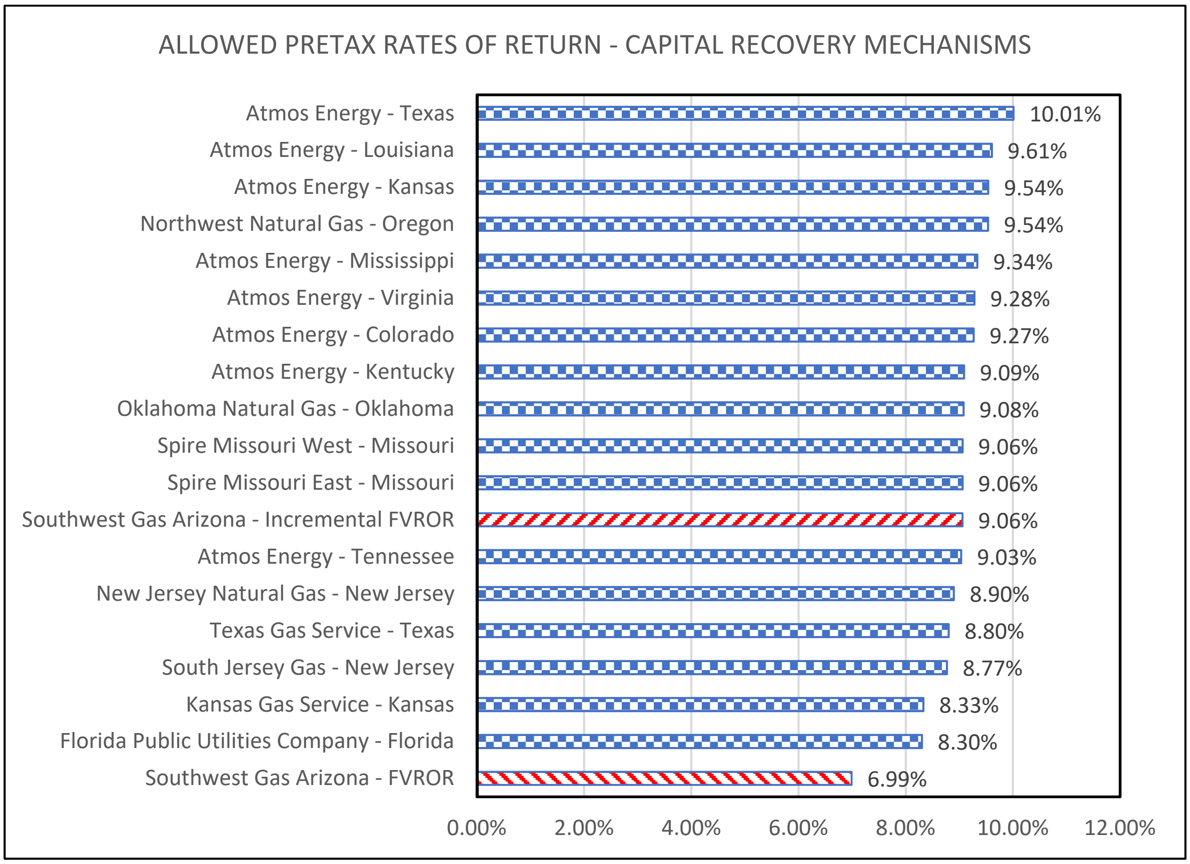
Q. 46 Please confirm the appropriateness of the incremental FVROR by demonstrating that it results in an equivalent revenue requirement as compared to a general rate case.

A. 46 Holding all else constant, adding the incremental FVRB of $100 million via a general rate case methodology will result in the same revenue requirement if a surcharge was computed utilizing the incremental FVROR for the $100 million increase in the FVRB. Exhibit No.__(TKW-3), displays the calculation of the revenue requirement using the incremental FVROR and authorized FVROR for the $100 million of incremental investment related FVRB. Using the incremental FVROR to compute a surcharge of $10,481,000 and adding that amount to the existing revenue requirement of $146,048,399 results in a total revenue requirement of $156,529,399. If the revenue requirement was computed using the general rate case methodology that included the incremental investment FVRB, the total revenue requirement would be $156,529,399, which is exactly the amount computed using the incremental FVROR to compute a surcharge and adding to the existing revenue requirement.

In contrast, using the authorized FVROR results in a surcharge of $8,109,002 and adding that amount to the existing revenue requirement of $146,048,399 results in a total revenue requirement of $154,157,401. Again, if the revenue requirement was computed using the general rate case methodology that included the incremental investment FVRB, the total revenue requirement would be $156,529,399. The use of the authorized FVRB, which does not take in to account the dynamic nature of how the FVROR changes when new rate base is added, results in a revenue deficiency of $2,371,998. Clearly, simply using the authorized FVROR to calculate the revenue requirement on incremental investment is flawed Therefore, the FVROR for any capital cost recovery or tracking mechanism should be the incremental FVROR, which is developed in the same manner as the FVROR in a general rate case. Please refer to the prepared direct testimony of Company witness Randi L. Cunningham for options for the Commission to consider when applying the appropriate FVROR for a cost recovery or tracking mechanism.

Q. 47 How does using the incremental FVROR impact the comparability to the proxy group companies used to estimate the cost of equity?

A. 47 For the capital tracking mechanisms utilized by the proxy group companies, the authorized pretax rates of returns range from 8.30% to 10.01%, with an average pretax rate of return of 9.12%.[22] The following graph displays the proxy groups authorized pretax rates of return for capital tracking mechanisms.



By way of comparison, the pretax rate of return for the Company's VSP mechanism based on the current FVROR of 5.71% grossed-up for taxes is 6.99%, which is 213 basis points below the average return of the proxy group. If the incremental FVROR is used, the pretax rate of return would be 9.06%, which

22 See Exhibit No.____(TKW-4) Pretax Rates of Return of the Proxy Group Capital Recovery Mechanisms.

is much closer and comparable to the average authorized pretax rate of return of 9.12% for the proxy group companies. This provides additional corroborating evidence of why the incremental FVROR is the appropriate rate of return for capital cost recovery or tracking mechanisms.

Q. 48 Does this conclude your prepared direct testimony?

A. 48 Yes.

SUMMARY OF QUALIFICATIONS
THEODORE K. WOOD

I graduated from the University of Nevada, Reno (UNR) in 1985 with a Bachelor of Science degree with a major in agricultural economics. In 1989, I earned a Master of Science degree from UNR in agricultural economics with a minor in finance. I have attained the professional designations of Chartered Financial Analyst (CFA), Certified Rate of Return Analyst (CRRA), Certified Management Accountant (CMA), Certified in Financial Management (CFM), and Certified Treasury Professional (CTP). I am a member of the Institute of Management Accountants, the CFA Institute, Association for Financial Professionals, Financial Management Association, and the Society of Regulatory and Utility Financial Analysts.

From 1985 to 1988, I was employed as a research associate in the Department of Agricultural Economics at UNR in Reno, Nevada. My primary role was to assist with ongoing research projects in the Department including secondary data collection, statistical analysis, FORTRAN programming, and the development of microcomputer spreadsheets for farm management decision analysis.

In 1989, I was employed by First Interstate Bank of Nevada in Reno, Nevada, as a financial analyst in the Finance Department. My duties entailed maintenance of the general ledger system, creation of monthly management and financial reports, and special projects.

From 1990 to 1992, I was employed as a planning analyst with Valley Bank of Nevada, in Las Vegas, Nevada, in the Planning Department. My primary responsibilities included preparation of the annual budget, quarterly budget variance analysis, supporting the Asset/Liability Committee of the bank, and other financial analyses.

From 1992 to 1994, I was employed by PriMerit Bank, FSB, then a wholly-owned subsidiary of Southwest Gas, as a Senior Financial Analyst in the Budget and Forecasting Department. My primary responsibilities included creation and maintenance of a microcomputer-based budgeting system, preparation of the annual budget, monthly budget variance analysis, product profitability analysis, and other special projects.

In 1994, I accepted a Senior Financial Analyst position in the Treasury Services Department of Southwest Gas. I was promoted to Supervisor of the Treasury Services Department in May 1997, to Manager in June 2000, to Senior Manager in May 2005 and Assistant Treasurer/Director of Financial Services in December 2009. My responsibilities include directing the Company's treasury and corporate planning functions and assisting with certain investor relations activities, which includes meeting with institutional equity and fixed income analysts, as well as rating agencies. In addition, my responsibilities include representing the Company in various regulatory proceedings in its ratemaking jurisdictions concerning regulatory finance issues.

MOODY'S
INVESTORS SERVICE

CREDIT OPINION

4 January 2019

Update

Rate this Research

RATINGS

Southwest Gas Corporation

Domicile	Las Vegas, Nevada, United States
Long Term Rating	A3
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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EMEA	44-20-7772-5454

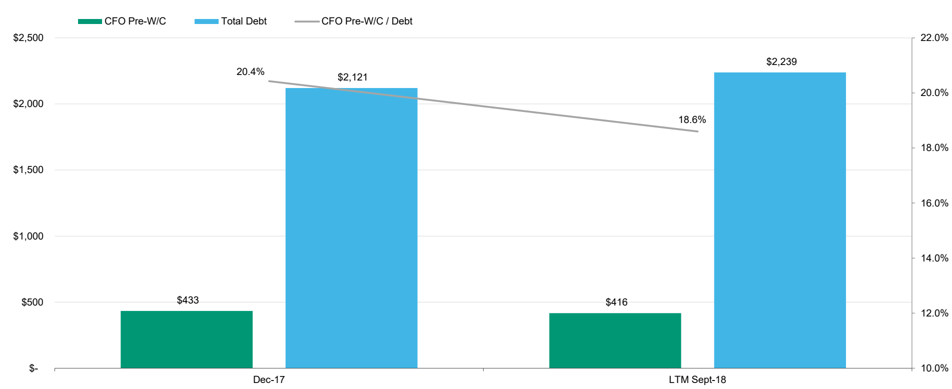
Southwest Gas Corporation

Update to credit analysis

Summary

Our credit assessment of Southwest Gas Corporation (Southwest Gas) reflects its low business risk profile as a natural gas local distribution company (LDC) operating in the credit supportive regulatory environments of Arizona, California and Nevada. We see Southwest Gas' financial metrics weakening over the next few years as the company increases debt to fund capital expenditures. We also take into consideration the potential contagion risk associated with the unregulated operations of Centuri Construction Group (Centuri, not rated), an affiliated company. However, with the reorganization under parent holding company Southwest Gas Holdings (Southwest Holdings, Baa1 stable), there is greater separation between Southwest Gas and Centuri, which reduces the probability that Southwest Gas will be negatively impacted by risks associated with the unregulated business.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



Source: Moody's Investors Service

Credit Strengths

» Approximately $3 billion rate base LDC operations with a low business risk profile

» Credit supportive regulatory environments

» Credit metrics supported by transparent cash flows

Credit Challenges

» Increasing leverage to support capital program

» Weakening credit metrics

» Potential contagion risk from the parent company's growing exposure to higher risk conconstruction and other non-utility operations, although holding company structure reduces this risk to some degree

Rating Outlook

Southwest Gas' stable rating outlook is based on our expectation that the regulatory jurisdictions under which it operates will remain credit supportive and continue to support predictable and stable cash flows. The outlook also assumes that the company's financial metrics, including cash flow from operations pre-working capital (CFO pre-WC) to debt will be maintained around 20%.

Factors that Could Lead to an Upgrade

» A significant improvement in the regulatory environments where regulatory lag is shortened meaningfully and the returns on investments increase materially

» If key credit metrics improve, including CFO pre-WC to debt above 24% on a sustained basis

Factors that Could Lead to a Downgrade

» A decline in the supportiveness of the regulatory environments under which the company operates, resulting in longer regulatory lag and lower returns on investments

» Continued expansion of parent's unregulated construction business, increasing contagion risk for the utility

» A significant increase in parent debt that puts additional pressure on the utility's cash flow or financial profile

» A deterioration of key financial metrics, including a ratio of CFO pre-WC to debt below 17% on a sustained basis

Key Indicators

Exhibit 3
KEY INDICATORS [1]
Southwest Gas Corporation

	Dec-17	LTM Sept-18
CFO Pre-W/C + Interest / Interest	6.9x	5.5x
CFO Pre-W/C / Debt	20.4%	18.6%
CFO Pre-W/C – Dividends / Debt	16.6%	14.8%
Debt / Capitalization	50.9%	50.5%

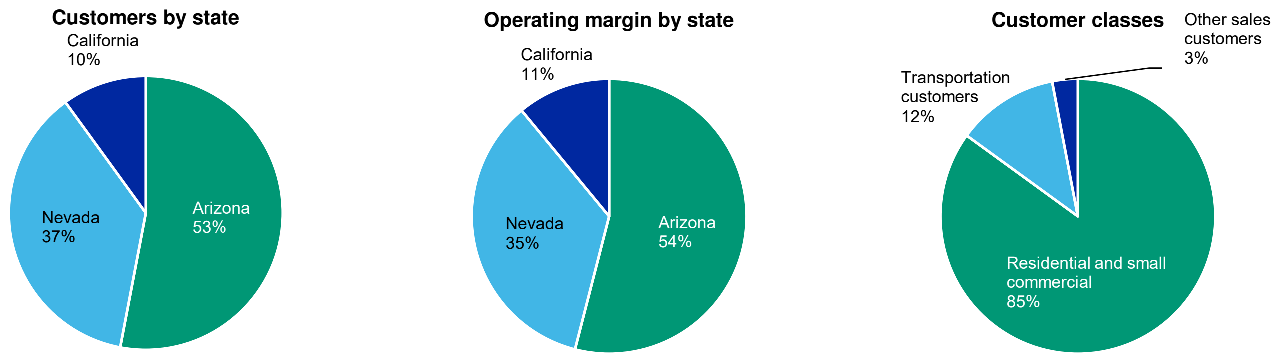
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Profile

Southwest Gas Corporation (Southwest Gas, A3 stable) is a natural gas local distribution company (LDC) subsidiary of Southwest Gas Holdings, Inc. (Southwest Holdings, Baa1 stable), serving central and southern Arizona, the Las Vegas Metropolitan area and northern Nevada, and Lake Tahoe and San Bernardino County in California. Through its LDC operations, Southwest Gas purchases, transports and distributes natural gas to 2 million customers in its service territories. The company's natural gas operations include Paiute Pipeline Company (Paiute), a pipeline transmission system. Southwest Gas' natural gas operations contributed approximately

80% of consolidated net income to the parent in 2017. Natural gas operations are regulated by the Arizona Corporation Commission (ACC), the Public Utilities Commission of Nevada (PUCN), the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

Exhibit 4
Customer and operating margin distribution for the 12 months ended 30 June 2018



Source: Southwest Gas Holdings

Effective January 2017, Southwest Gas and Centuri are separate subsidiaries of a new publicly traded parent holding company, Southwest Gas Holdings.

Detailed Credit Considerations

- LDC operations with a low business risk profile

Southwest Gas is a low risk natural gas distribution utility and the primary subsidiary of Southwest Gas Holdings. Southwest Gas' LDC operations make up a majority of Southwest Holdings' consolidated earnings. At 30 September 2018, the LDC operations contributed approximately 74% of the company's $209 million latest twelve months (LTM) net income. The customer base for the LDC operations is 85% residential and small commercial, which provides a stable and consistent foundation for its operations. For the 12 months ended 30 September 2018, customer growth was approximately 1.6% and we expect that Southwest Gas will continue to experience customer growth around this level in its service territory over the next 12-18 months.

- Credit supportive regulatory jurisdictions

We view the regulatory environments in which Southwest Gas operates as generally credit supportive. Southwest Gas is fully decoupled and has infrastructure recovery programs in all of its jurisdictions. The utility has a Customer-Owned Yard line program (COYL) in Arizona to replace and relocate eligible service lines and meters closer to buildings, reducing the amount of piping owned and maintained by property owners. The utility is also authorized a surcharge to recover the cost of depreciation and earns a pre-tax return on the costs incurred to replace and relocate service lines and meters.

In California, Southwest Gas is authorized a limited COYL program for schools and an associated Infrastructure Reliability and Replacement Adjustment Mechanism (IRRAM) to recover costs associated with the limited COYL program.

Southwest Gas was also recently authorized a COYL program in its northern Nevada rate jurisdiction as well as a COYL program in limited situations in southern Nevada. The utility has a Gas Infrastructure Replacement (GIR) mechanism in Nevada to defer and recover costs associated with accelerated infrastructure replacement and its approved COYL program. Southwest Gas requests approval from the PUCN to replace qualifying infrastructure through an annual Advance Application and separately files annually to reset the recovery surcharge for previously approved and completed projects.

Exhibit 5
Overview of utility operations

Rate jurisdiction	Authorized rate base (in thousands)	% of total rate base	Authorized rate of return	Authorized return on common equity	Decoupled (Y/N)	Authorized common equity ratio
Arizona	$1,324,902	46%	7.42%	9.50%	Y	51.70%
Southern Nevada	$1,110,380	38%	6.66%	9.25%	Y	49.66%
Northern Nevada	$134,230	5%	7.04%	9.25%	Y	49.66%
Southern California	$159,277	5%	6.83%	10.10%	Y	55.00%
Northern California	$67,620	2%	8.18%	10.10%	Y	55.00%
South Lake Tahoe	$25,389	1%	8.18%	10.10%	Y	55.00%
Paiute Pipeline Company [1]	$87,158	3%	8.46%	11.00%	Y	51.75%
Total	$2,908,956	100%				
Weighted average authorized ROE				9.49%		

[1] Estimated amounts based on rate case settlement
Source: Southwest Gas Holdings

In December 2018, the PUCN approved a rate change in Nevada based on a return on equity (ROE) of 9.25% and equity layer of 49.66%, with rates effective 7 January 2019. The authorized ROE and equity layer are below industry averages and the lowest amongst those of its other jurisdictions. The utility's request, filed on May 2018 and updated in August 2018, was for a statewide overall general rate increase of approximately $29.7 million which consisted of $12.1 million of changes in the cost of service, including the impact of tax reform, and $17.6 million associated with the inclusion in rate base of GIR projects previously approved by the PUCN under the GIR program. The request was based on an ROE of 10.3% and equity layer of 49.66%.

With regard to tax reform, the commission decided that Southwest Gas' unprotected excess accumulated deferred income taxes (ADIT) liability should be amortized over six years and protected excess ADIT liabilities be amortized over the remaining useful life of the underlying assets. The commission denied Southwest Gas' request to implement a pension tracker mechanism but approved the continuation of the utility's revenue decoupling mechanism. Also, the commission approved Southwest Gas' proposal to adjust the GIR surcharge rate.

Southwest Gas' most recent rate case in Arizona was decided on April 11, 2017 with rates effective as of April 1, 2017, when the ACC approved a settlement filed in January 2017. Terms of the adopted settlement were generally credit supportive. As part of its rate case filing in May 2016, Southwest Gas requested an increase in authorized annual operating revenues of $31.9 million, based on a 10.25% ROE and a 51.69% equity capitalization on a $1.34 billion rate base. The adopted settlement granted a $16 million increase in annual revenue, based on a 9.5% ROE and 51.70% equity capitalization on a $1.33 billion rate base.

In addition, Southwest Gas obtained approval to continue its revenue-per-customer decoupling mechanism. The COYL program was expanded to accelerate infrastructure replacements and the utility obtained approval to implement a new replacement program for approximately 6,000 miles of pre-1970s vintage steel pipe. The settlement also included a property tax tracking mechanism to defer changes in property tax expense for recovery or return in the next general rate case. Southwest Gas is prohibited from filing its next rate case in Arizona until May 2019. With regard to tax reform, the ACC in July 2018 approved a $20 million annual refund to customers.

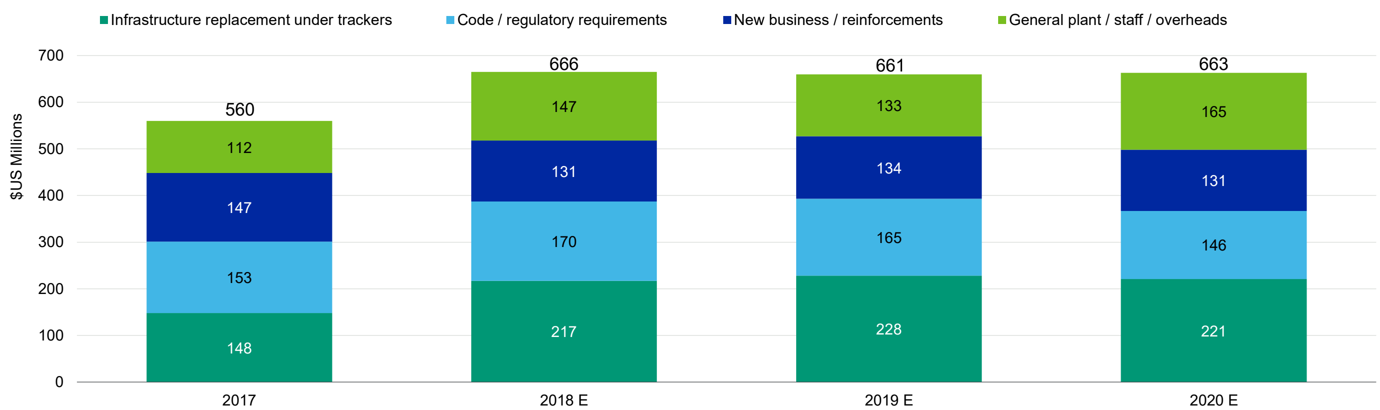
In June 2017, Southwest Gas received approval from the CPUC to extend the current rate case cycle in California by two years. The utility now expects to file its next rate case in California in 2019. The annual post-test year attrition adjustments in California, currently at 2.75%, will continue through 2020 when new rates become effective. Although the CPUC has not initiated formal proceedings to address tax reform, Southwest Gas has established a memorandum account, as directed by the CPUC, to track tax reform impacts for attrition years 2019 and 2020.

Construction is currently underway on Southwest Gas' proposed $80 million, 233,000 decatherm LNG facility in Southern Arizona. The LNG facility is designed to enhance service reliability and flexibility in natural gas deliveries in the southern Arizona area by providing a local storage option, operated by Southwest Gas and connected directly to its distribution system. Southwest Gas received pre-approval from the ACC in December 2014 to construct the LNG facility and to defer up to $50 million in associated costs. The Company purchased the site for the facility in October 2015. In December 2016, Southwest Gas received approval from the ACC to increase the amount of deferred costs by an additional $30 million to $80 million. Through September 2018 Southwest Gas has spent approximately $51 million in capital expenditures toward the project. Construction began in the third quarter of 2017 and is expected to be completed by the end of 2019.

- Increase in leverage to support capital program expected to weaken credit metrics

For the 2019-2020 period, Southwest Gas expects to spend over $1.2 billion in capital investments primarily to improve system flexibility and reliability, including replacement of early vintage plastic and steel pipes, as well as to support growth within its service territory. While we expect Southwest Gas will use a combination of internally generated cash flows, debt at the utility level and equity proceeds at the parent level to fund its capital investment program, it's credit metrics will be weakened by increased debt.

Exhibit 7
Planned capital expenditures through 2020



Source: Southwest Gas Holdings

For the 12 months ended 30 September 2018, CFO pre-WC to debt was approximately 18.6% and the CFO pre-WC interest coverage ratio was 5.5x. Although there have been improvements in Southwest Gas' regulatory frameworks, including the implementation of supportive cost recovery provisions such as infrastructure recovery mechanisms in all 3 regulatory jurisdictions, we see declining financials and key credit metrics over the next two years. We project CFO pre-WC/debt in the mid-to-high teens, around our indicated downgrade threshold of 17%, largely driven by increasing debt outpacing cash flow growth.

- Potential contagion risk from growing non-utility operations through Centuri Construction Group

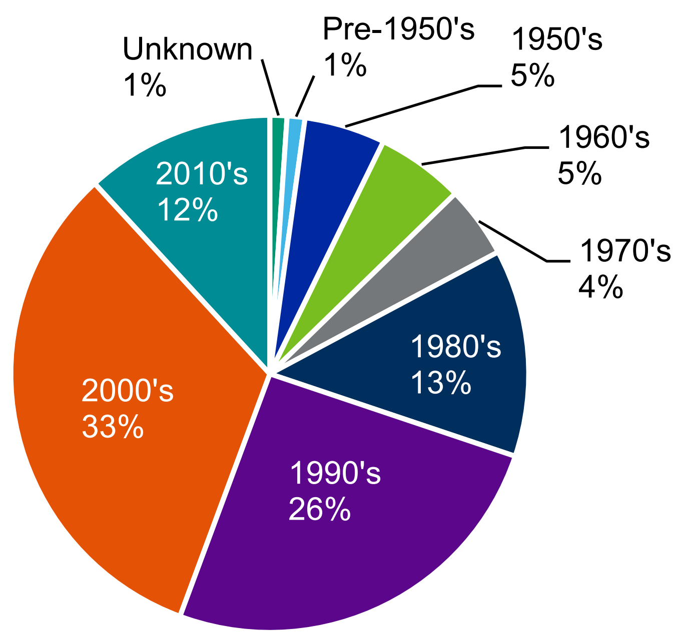
As part of a holding company reorganization effective January 2017, Centuri and Southwest Gas are now separate subsidiaries of a new publicly traded parent holding company, Southwest Gas Holdings. Prior to the reorganization, Centuri was a direct subsidiary of Southwest Gas. We view this change in organizational structure as credit positive because it provides additional separation between Southwest Gas and Centuri, reducing the likelihood of credit contagion from the unregulated businesses.

Centuri Construction Group was formed as an intermediate holding company with two direct subsidiaries that house unregulated companies. Centuri increases cash flow and earnings volatility for Southwest Holdings and consequently puts some pressure on Southwest Gas' credit because Centuri's operations are cyclical and subject to significant impacts from changes in weather and local economic conditions. However, Southwest Gas' credit incorporates our view that Centuri's operations are highly contracted, and thus insulate the utility subsidiary from some of the risk associated with non-utility operations. The utility's credit profile also incorporates our expectation that Southwest Holdings will manage Centuri conservatively and not grow it materially from its current scale such that financial and operating risks associated with the non-utility businesses are heightened.

- Low carbon transition risk

As a pure-play LDC with no fossil generation, Southwest Gas has low carbon transition risk within the regulated utility sector. The utility pipeline system is fairly modern, with 70% of its 55,000 miles of distribution and main and service lines installed post-1990. The company has no unprotected bare steel pipes and continues to work towards replacing vintage plastic pipes and vintage steel pipes in Arizona and Nevada.

Exhibit 8
Southwest Gas % of total pipe by decade of installation [1]



[1] Miles of pipe from each decade over Southwest Gas pipe network total mileage of 55,379
Source: Southwest Gas Holdings

Moody's framework for assessing carbon transition risk in the utility industry is discussed in "Prudent regulation key to mitigating risk, capturing opportunities of decarbonization" (November 2 2017).

Liquidity Analysis

We expect Southwest Gas to maintain an adequate liquidity profile over the next 12 months.

Southwest Gas has a $400 million credit facility which expires in March 2022. The company designates $150 million of the $400 million credit facility for long-term borrowings and the remaining $250 million for working capital expenses. Southwest Gas has a $50 million commercial paper program supported by the credit facility and, as of 30 September 2018, Southwest Gas had $150 million of long-term borrowings (including $50 million of commercial paper outstanding) and $9 million of short-term borrowings under the facility. As of 30 September 2018, the company was in compliance with the facility's financial covenant to maintain a debt to capitalization ratio below 70%. Borrowings under the facility are not subject to a material adverse change clause.

At 30 September 2018, Southwest Gas had approximately $49 million of cash on hand and reported cash from operations of $385 million for the twelve months ended 30 September 2018. The company had capital expenditures of $651 million and paid dividends of $86 million for the same period.

Southwest Gas' next long-term debt maturity is $125 million of senior notes due in December 2020.

Rating Methodology and Scorecard Factors

Exhibit 9
Rating Factors
Southwest Gas Corporation

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2018		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	5.5x	A	4.5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	18.6%	Baa	16% - 18%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	14.8%	Baa	11% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	50.5%	Baa	48% - 52%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2018(L);
[3] This represents Moody's forward view; not the view of the issuer; and unless noted xin the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Ratings

Exhibit 11

Category	Moody's Rating
SOUTHWEST GAS CORPORATION	
Outlook	Stable
Senior Unsecured	A3
PARENT: SOUTHWEST GAS HOLDINGS, INC.	
Outlook	Stable
Issuer Rating	Baa1

Source: Moody's Investors Service

Appendix

Exhibit 12
Cash Flow and Credit Measures [1]

CF Metrics	Dec-17	LTM Sept-18
As Adjusted		
EBITDA	**515**	**496**
FFO	**437**	**412**
- Div	81	86
RCF	**81**	**86**
FFO	437	412
+/- ΔWC	(104)	(12)
+/- Other	(4)	5
CFO	**329**	**404**
- Div	81	86
- Capex	565	655
FCF	**(317)**	**(337)**
Debt / EBITDA	4.1x	4.5x
EBITDA / Interest	7.0x	5.3x
FFO / Debt	20.6%	18.4%
RCF / Debt	16.8%	14.6%
Revenue	1,302	1,354
Cost of Good Sold	345	402
Interest Expense	73	93
Net Income	168	158
Total Assets	5,502	5,831
Total Liabilities	3,904	4,125
Total Equity	1,599	1,706

[1] All figures & ratios calculated using Moody's estimates & standard adjustments.
Source: Moody's Financial Metrics

Exhibit 14
Peer Comparison [1]

	Southwest Gas Corporation A3 Stable		ONE Gas, Inc A2 Negative		Washington Gas Light Company A2 Negative		Atmos Energy Corporation A2 Positive	
	FYE	LTM	FYE	LTM	FYE	LTM	FYE	LTM
(in US millions)	Dec-17	Sept-18	Dec-17	Sept-18	Sep-17	Sept-18	Sep-17	Sept-18
Revenue	1,302	1,354	1,540	1,632	1,167	1,248	2,760	3,116
EBITDA	515	496	481	475	428	408	1,082	1,115
CFO Pre-W/C / Debt	20.4%	18.6%	22.1%	28.5%	20.6%	7.7%	27.2%	27.2%
CFO Pre-W/C – Dividends / Debt	16.6%	14.8%	16.9%	22.6%	15.2%	2.1%	22.0%	21.5%
Debt / EBITDA	4.1x	4.5x	3.5x	3.4x	3.7x	3.8x	3.4x	3.4x
Debt / Capitalization	50.9%	50.5%	40.0%	38.0%	44.0%	45.8%	39.0%	39.1%
EBITDA / Interest Expense	7.0x	5.3x	8.5x	8.3x	6.7x	5.8x	8.6x	9.3x

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year End. LTM = Last Twelve Months.
Source: Moody's Financial Metrics

REPORT NUMBER 1152872

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S
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Summary:

Southwest Gas Corp.

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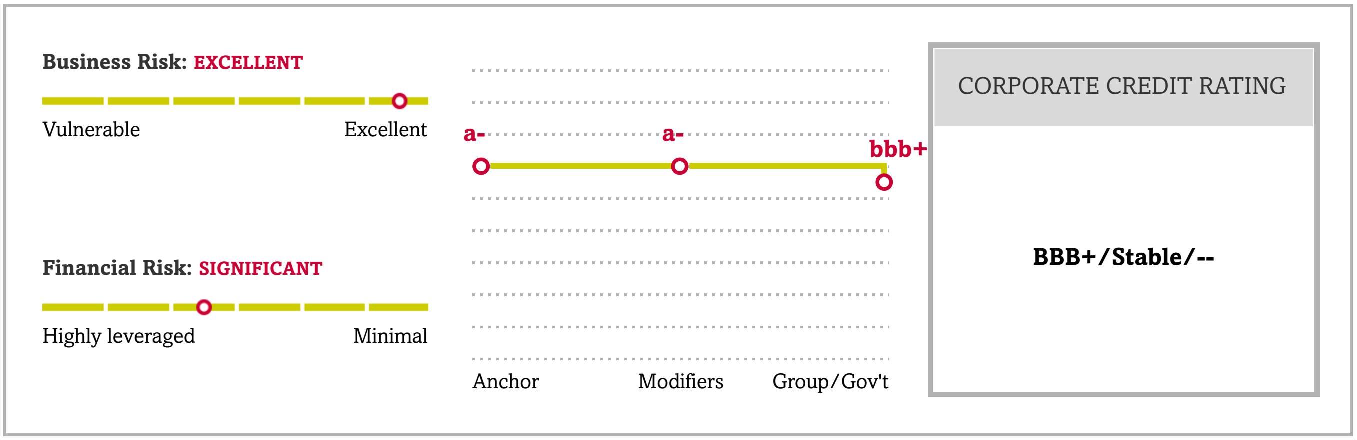
Summary:

Southwest Gas Corp.



Rationale

Business Risk: Excellent	Financial Risk: Significant
• Southwest Gas Corp (SWGC) is a low-risk and rate-regulated natural gas distribution utility. • We view the company's overall management of regulatory risk as generally consistent with peers. • The company has geographical and regulatory diversity spanning three states (Arizona, Nevada, and California). • The company's large, mostly residential customer base provides stability to its revenues. • It has a diverse source of natural gas supply.	• We assess SWGC's financial measures using moderate financial benchmarks compared to the typical corporate issuer, reflecting its low-risk, regulated gas utility operations and effective management of regulatory risk. • We expect SWGC's financial measures, including funds from operations (FFO) to debt, to gradually weaken beginning in 2018 mainly due to the company's elevated capital spending, and the effects of tax reform. • We expect the effects of the recently revised U.S. corporate tax code to be mostly manageable for SWGC, in part reflecting cushion in the company's current financial measures. • We expect SWGC to experience negative discretionary cash flows for the next several years primarily due to its high capital spending requirements and dividend payments.

Outlook: Stable

The stable outlook on Southwest Gas Corp. (SWGC) reflects S&P Global Ratings' expectations that parent company Southwest Gas Holdings Inc.'s (SWGHI) construction services business will reflect no more than 25% of the consolidated company's earnings, and that core credit ratios for SWGHI will consistently reflect FFO to debt that ranges from 23%-25%.

Downside scenario

We could lower the rating if the consolidated business risk profile for the parent weakens either because of less-than-effective management of regulatory risk or due to a disproportional growth of SWGHI's construction business so that it represents more than 30% of the consolidated company. We could also lower the rating if core credit ratios for SWGHI materially weaken, reflecting FFO to debt that is consistently lower than 21%.

Upside scenario

We could raise the rating if parent SWGHI permanently reduces the size of its higher-risk construction services business to below 20% of the consolidated company or if the company's core credit ratios improve, reflecting FFO to debt that consistently exceeds 32%.

Our Base-Case Scenario

Assumptions

- Continued use of constructive regulatory mechanisms, including infrastructure riders in key jurisdictions;
- Rate case moratorium in Arizona until May 2019;
- Capital spending averaging over $600 million annually;
- Customer growth rate of about 1.5%;
- Annual dividends averaging about $90 million; and
- Negative discretionary cash flow for the next several years.

Key Metrics

	2017A	2018E	2019E
FFO/debt (%)	20.9	17-18	17-18
Debt/EBITDA (x)	4	4-4.2	4-4.2

A--Actual. E--Estimate.

Company Description

SWGC is a regulated natural gas utility that purchases, distributes, and transports natural gas to close to 2 million customers across parts of Arizona, Nevada, and California. SWGC is a wholly owned subsidiary of parent Southwest Gas Holdings Inc. (SWGHI) and contributes about 80% of SWGHI consolidated operating earnings.

Business Risk: Excellent

Our business risk assessment of SWGC incorporates our view of the company's low-risk, rate-regulated gas utility operations based exclusively in the U.S. Our business risk assessment also reflects the company's overall management of regulatory risk, stable customer base, and diverse source of natural gas supply. SWGC serves close to 2 million mostly residential and commercial customers and is regulated by the Arizona Corporation Commission (ACC) (50% of rate base), the Public Utilities Commission of Nevada (PUCN) (35% of rate base), and the California Public Utilities Commission (CPUC) (10% of rate base). The remainder of the company's operations consist of a Federal Energy Regulatory Commission (FERC)-regulated pipeline transmission system (Paiute Pipeline Co.) that we view as low risk. As such, we expect the company's regulatory diversity and scale to continue to support SWGC's stable profitability measures, which we view as favorable for credit quality.

We view the company's management of regulatory risk as generally consistent with peers. This largely reflects the use of credit-supportive mechanisms, including cost recovery riders for purchased gas, infrastructure replacement, and decoupling, but is partly offset by the use of historic test periods for rate-making in Arizona and Nevada. In addition, we expect the company's diverse natural gas supply mix to continue to result in steady reliable natural gas service for SWGC's customers.

In April 2017, the ACC approved a $16 million general rate increase including a depreciation study that resulted in a combined net operating income increase of close to $61 million. The ACC order also includes a rate case moratorium for SWGC until May 2019.

Financial Risk: Significant

We assess SWGC's financial risk measures using moderate financial benchmarks compared to the typical corporate issuer reflecting the company's low-risk, regulated gas business, and management of regulatory risk. Under our base-case scenario, reflecting capital spending that averages over $600 million, dividend payments of about $90 million, customer growth of about 1.5%, the continued use of existing regulatory mechanisms, and a rate-case moratorium in Arizona until May 2019, we expect FFO to debt of to range from about 17%-18%. In addition, we expect a gradual weakening of the company's financial measures, mainly due to its elevated capital spending. Furthermore, we expect the effects of the recently revised U.S. corporate tax code to be mostly manageable for the company, in part reflecting cushion in the company's current financial measures.

Liquidity: Adequate

SWGC has adequate liquidity, in our view, and could more than cover its needs for the next 12 months, even if EBITDA declines by 10%. We expect the company's consolidated liquidity sources will exceed uses by more than 1.1x over the next 12 months. Under our stress scenario, we do not expect SWGC to seek access to the capital markets during that period to meet liquidity needs. Our assessment also reflects the company's generally prudent risk management, sound relationships with banks, and a generally satisfactory standing in the credit markets.

Principal liquidity sources

- Cash FFO of about $420 million.
- Credit facility of about $300 million.
- Available cash of close to $38 million.

Principal liquidity uses

- Maintenance capital spending of about $ 500 million.
- Dividend payments of about $90 million.
- No long-term debt maturities in 2018.

Group Influence

We assess SWGC as a core subsidiary of parent SWGHI. Our assessment reflects our view that SWGC is highly unlikely to be sold, operates in a line of business that is integral to SWGHI's future strategy, has a strong long-term commitment from SWGHI's senior management, and is closely linked to the group's name and reputation.

Ratings Score Snapshot

Corporate Credit Rating

BBB+/Stable/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** bbb+
- **Entity status within group:** Core (-1 notch from SACP)

Issue Ratings--Subordination Risk Analysis

Capital structure

SWGC's capital structure consists of about $1.52 billion of senior unsecured debt issued at SWGC.

Analytical conclusions

SWGC's debt is rated 'BBB+', the same as our issuer credit rating on the company, because it is unsecured debt of a qualifying investment-grade regulated utility.

Related Criteria

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, Sept. 21, 2017
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - Industrials: Key Credit Factors For The Engineering And Construction Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

FitchRatings

21 Jun 2018 | Affirmation

Fitch Affirms Southwest Gas and Sub. At 'A-' and 'BBB+'; Outlook Stable

Fitch Ratings-New York-21 June 2018: Fitch Ratings has affirmed the long-term Issuer Default Ratings (IDR) of Southwest Gas Holdings, Inc. (SWX) at 'BBB+' and Southwest Gas Corporation (SWG) at 'A-'. The Rating Outlooks are Stable. Fitch has also affirmed the $50 million Clark County, Nevada Industrial Revenue Development bonds (Southwest Gas Corp Project) Series 2003A at 'AA-'/'F1+' based on the irrevocable direct-pay letter of credit (LOC) provided by JPMorgan Chase Bank, N.A. (JPM, rated 'AA-/F1+).

SWX and SWG's ratings and Outlooks primarily reflect the constructive regulatory environment across the utility's service territory, including revenue decoupling and purchased gas adjustment mechanisms (PGAs) in all jurisdictions and the company's sound financial metrics. SWX's ratings also consider the riskier construction services business at Centuri Construction Group Inc., and the elevated capex program at the utility.

The Clark County bonds enhanced rating is based on the criteria, dated February 22, 2018, titled 'U.S. Public Finance Letter of Credit-Supported Bonds and Commercial Paper Rating Criteria' available at www.fitchratings.com. The rating reflects the higher of the unenhanced long-term rating assigned to the bonds by Fitch (SWG rated A/Stable outlook) and the long-term rating assigned to JPM, the bank providing the substitute LOC securing the bonds. The Short-Term 'F1+ rating is based solely on the LOC.

KEY RATING DRIVERS

SWX
Ownership of SWG: SWX benefits from the company's ownership of SWG, a regulated natural gas distribution company, which accounts for about 80% of consolidated EBITDA. SWG's low-risk local distribution company (LDC) operations support credit quality. Fitch expects the utility to maintain its steady contribution to SWX despite the organic growth and smaller acquisitions completed at Centuri, its construction services subsidiary.

Moderate Risk in Construction Services Business: Fitch considers Centuri's business risk to be higher than the regulated utility. Centuri is a full-service contractor that works with LDCs to install, repair and maintain pipeline distribution systems in the U.S. and Canada. Centuri contributed approximately 20% of consolidated EBITDA for the last 12 months ended March 31, 2018, and Fitch expects Centuri's EBITDA contribution to remain around that level going forward.

Subsidiary-Level Debt: Over 90% of the consolidated debt is at the subsidiary, SWG. Prior to 2017, Centuri was a subsidiary of SWG. Following a reorganization that was effective Jan. 1, 2017, Centuri became an indirect subsidiary of SWX and deconsolidated its operations from SWG and implemented ring fencing provisions. SWX benefits from the deconsolidation as it receives upstream dividends from Centuri to support a minimal amount of holding company debt and consequently has lower consolidated leverage than the utility.

Federal Tax Reform: Fitch believes SWG will assess the impact of the reduction in the federal rate to 21% from 35% and take actions to maintain supportive credit metrics. The Arizona Corporation Commission, the Nevada Public Utility Commission and the California Public Utilities Commission have opened a case to refund to customers the benefits from the reduced federal income tax rate. Fitch believes the reduction in cash flow of about $30 million-$35 million in 2018 increased leverage by around 20 basis points.

SWG

Low Risk Business Model: SWG's ratings reflect the low risk business profile of its regulated gas utility business. The ratings benefit from a relatively constructive regulatory environment. The utility's natural gas distribution business has revenue decoupling, purchased gas adjustment and infrastructure recovery mechanisms throughout its service territory. These rate mechanisms increase the stability and predictability of earnings and cash flows and provide for timely cost recovery.

Modest Regulatory Diversification: SWG's natural gas distribution business has a modest level of regulatory diversification, which helps limit exposure to any one jurisdiction. In 2018, Arizona and Nevada accounted for 54% and 35%, respectively, of the utility's operating income, while California accounted for 11%. SWG filed a GRC in Nevada in May 2018 requesting a 9% rate increase in southern Nevada, based on a 10.3% ROE and a 49.4% equity ratio and a 3% rate increase, based on a 10.3% ROE on a 49.3% equity ratio in northern Nevada. The current rate order has been in place since March 2013 when the PUCN authorized a 10.0% ROE and a 42.7% equity ratio in southern Nevada and a 9.3% ROE on a 59.1% equity ratio in northern Nevada.

Elevated Capex Program: SWG increased its capital program, primarily focused on safety and reliability. Fitch expects consolidated capex from 2018 to 2020 to total $1.9 billion to $2.1 billion, with 90% to 95% for the utility. About half of the program costs are recovered through infrastructure trackers earning a return within one year; the remainder is subject to general rate case proceedings resulting in more than a one year lag. Concerns regarding the relatively large capex program are somewhat mitigated by the utility's various infrastructure replacement cost-recovery mechanisms.

Strong Financial Metrics: The relatively constructive regulatory environment has enabled consolidated financial metrics to remain strong. Through 2020, Fitch expects SWX to maintain financial metrics supportive of the ratings, despite the increase in leverage driven by the utility's larger capex program. Fitch expects FFO fixed-charge coverage between 5.9x and 6.2x, FFO-adjusted leverage of 3.6x to 3.8x and adjusted debt/EBITDAR of 3.6x to 3.9x.

Ring-Fencing of the Utility: SWG and Centuri are indirect subsidiaries of SWX. After the holding company formation in 2017, SWG has a layer of protection between parent SWX and Centuri from the ring-fencing provisions between the regulated natural gas distribution business and Centuri's unregulated construction services business. These ring-fencing measures include commitments to maintain separate books and records, a prohibition on commingling of funds and an independent director. SWX also has a non-consolidation opinion for the utility. Weak linkage exists between SWG's and SWX's ratings under Fitch's parent and subsidiary linkage criteria. Fitch would consider a difference of up to two notches between SWX's and SWG's long-term IDRs.

DERIVATION SUMMARY

SWX's business risk profile as a regulated utility holding company is comparable to its peers Eversource (BBB+/Positive Outlook), WEC Energy (BBB+/Stable Outlook) and WGL Holdings (A-/Rating Watch Negative). Eversource has a somewhat stronger business profile due to its FERC-regulated transmission operations, which Fitch views as low risk. WGL Holdings has a risker business profile due to its midstream operations and is on Negative Watch because of its pending acquisition by AltaGas Ltd. While SWX receives about 20% of EBITDA from its higher risk construction company subsidiary, Centuri, the company is similar to Eversource, WEC and WGL as a regulated parent holding company with natural gas distribution subsidiaries rated in the 'BBB+' to 'A-' range. WEC has greater regulatory diversity across eight jurisdictions, while SWX and Eversource are comparable, located in three jurisdictions. The financial metrics for SWX are better than its peers. At Dec. 30, 2017, adjusted debt/EBITDAR and FFO-adjusted leverage at SWX were 3.6x and 3.7x, respectively, more favorable than 5.8x and 4.7x at WGL, 5.0x and 5.7x at Eversource, and 4.2x and 4.6x at WEC, respectively.

SWG's credit profile (A-/Stable Outlook) has a somewhat weaker financial position than other LDCs. SWG is larger and has higher customer growth (1.6% over the next three years) than its similarly rated peers NSTAR Gas Co (NSTAR Gas, A-/Stable Outlook), Peoples Gas Light and Coke co (Peoples Gas, A-/Stable Outlook) and DTE Gas Co (DTE Gas, BBB+/Stable Outlook). All three peers operate in constructive regulatory environments that allow for automatic recovery mechanisms such as revenue decoupling, purchased gas costs and capex, a key driver for the rating stability. SWG's credit metrics are slightly weaker than its peers and will remain elevated due to its infrastructure replacement capex program. SWG's adjusted debt/EBITDAR and FFO-adjusted leverage were 3.6x and 3.7x, respectively, at Dec 31, 2017, slightly more favorable than Peoples Gas at 3.4x and 6.5x, NSTAR Gas at 4.8x and 5.0x and DTE Gas at 3.9x and 4.5x, respectively.

KEY ASSUMPTIONS

Fitch's Key Assumptions Within the Rating Case for the Issuer
--Net customer growth averaging 1.6% CAGR through 2020 in line with the growth in the service territory;
--Capital program of $1.9 billion during the three years 2018 to 2020;
--Utility operations contribute 80% of the consolidated EBITDA on average through 2020;
--Fitch's estimated impact of the tax reductions from 35% to 21% including a reduction in capex by $50 million in 2019-2020;
--Rate case completed in NV in 2019.

RATING SENSITIVITIES

SWX:
Developments that May, Individually or Collectively, Lead to Positive Rating Action

A ratings upgrade is unlikely at this time due to the utility's elevated capex program. Positive rating momentum could result from adjusted debt/EBITDAR below 3.0x on a sustained basis. SWX's long-term IDR is limited to a two-notch difference from that of SWG.

Developments that May, Individually or Collectively, Lead to Negative Rating Action

A negative rating action could result from a significant deterioration of the regulatory environment in Arizona or Nevada, a material expansion of Centuri's business activities to greater than 20% to 25% of consolidated EBITDA, or if FFO-adjusted leverage exceeded 4.5x and adjusted debt/EBITDAR exceeded 4.0.x on a sustained basis. A multi-notch downgrade of SWG could also result in a negative rating action for SWX.

SWG:

Developments that May, Individually or Collectively, Lead to Positive Rating Action

A ratings upgrade is unlikely at this time due to the utility's elevated capex program.

Developments that May, Individually or Collectively, Lead to Negative Rating Action

A negative rating action could result from a significant deterioration of the regulatory environment in Arizona or Nevada or if FFO-adjusted leverage exceeded 4.5x and adjusted debt/EBITDAR exceeded 4.0x on a sustained basis. A multi-notch downgrade of SWX could also result in a negative rating action for SWG.

LIQUIDITY

Fitch considers SWX's and SWG's liquidity adequate.

SWX primarily meets its short-term needs through a $100 million revolving credit facility. The company set up the facility in 2017 after the reorganization; the facility matures on March 28, 2022. As of March 31, 2018, SWX had $22.5 million outstanding under the credit facility.

SWG primarily meets its short-term liquidity needs through the issuance of CP under an uncommitted $50 million CP program. The program is supported by a $400 million revolving credit facility that was increased from $300 million and extended to March 28, 2022. As of March 31, 2018, SWG had $39 million under both its CP program and its credit facility.

SWG's operations require modest cash on hand to fund its daily business needs. At March 31, 2018, the company had $45.8 million of unrestricted cash and cash equivalents.

Centuri is self-funding and maintains access to liquidity through its $450 million secured revolving credit and term loan facility, which expires in November 2022. At March 31, 2018, Centuri had $176 million of availability under the revolving credit facility, which the company increased to fund acquisitions and working capital needs. Centuri's assets secure the facility and, as of March 31, 2018, totaled $592 million.

FULL LIST OF RATING ACTIONS

Fitch has affirmed the following ratings:
Southwest Gas Holdings, Inc.
- Long-term IDR at 'BBB+'; Stable Outlook.

Southwest Gas Corporation
- Long-term IDR at 'A-'; Stable Outlook;
- Short-term IDR at 'F2';
- Senior unsecured rating at 'A';
- Clark County, NV Industrial Development Revenue Bonds (Southwest Gas Corporation Project), Series 2003A enhanced by JPMorgan Chase Bank, N.A (JPM, rated 'AA-'/'F1+') at 'AA-/F1+', underlying rating of 'A';
- Commercial Paper at 'F2'.

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Additional information is available on www.fitchratings.com

Applicable Criteria

Corporate Rating Criteria (pub. 23 Mar 2018)

Corporates Notching and Recovery Ratings Criteria (pub. 23 Mar 2018)

Parent and Subsidiary Rating Linkage (pub. 15 Feb 2018)

U.S. Public Finance Letter of Credit-Supported Bonds and Commercial Paper Rating Criteria (pub. 22 Feb 2018)

Additional Disclosures

Dodd-Frank Rating Information Disclosure Form

Solicitation Status

Endorsement Policy

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SOUTHWEST GAS CORPORATION
PROXY GROUP COMPANIES
THREE-YEAR AVERAGE CAPITALIZATION STATISTICS

PERMANENT CAPITAL STRUCTURE

Line No.	Company	Long-Term Debt	Preferred Equity	Common Equity	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	ATMOS ENERGY CORP (ATO)	41.2%	0.0%	58.8%	100.0%	1
2	CHESAPEAKE UTILITIES CORP (CPK)	30.3%	0.0%	69.7%	100.0%	2
3	NEW JERSEY RESOURCES CORP (NJR)	46.0%	0.0%	54.0%	100.0%	3
4	NORTHWEST NATURAL GAS (NWN)	47.1%	0.0%	52.9%	100.0%	4
5	ONE GAS INC (OGS)	38.2%	0.0%	61.8%	100.0%	5
6	SOUTH JERSEY INDUSTRIES, INC (SJI)	52.6%	0.0%	47.4%	100.0%	6
7	SPIRE INC (SR)	51.0%	0.0%	49.0%	100.0%	7
8	Average	43.8%	0.0%	56.2%	100.0%	8

TOTAL CAPITAL STRUCTURE

Line No.	Company	Total Debt	Preferred Equity	Common Equity	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	
9	ATMOS ENERGY CORP (ATO)	45.7%	0.0%	54.3%	100.0%	9
10	CHESAPEAKE UTILITIES CORP (CPK)	47.0%	0.0%	53.0%	100.0%	10
11	NEW JERSEY RESOURCES CORP (NJR)	50.4%	0.0%	49.6%	100.0%	11
12	NORTHWEST NATURAL GAS (NWN)	50.0%	0.0%	50.0%	100.0%	12
13	ONE GAS INC (OGS)	41.1%	0.0%	58.9%	100.0%	13
14	SOUTH JERSEY INDUSTRIES, INC (SJI)	57.2%	0.0%	42.8%	100.0%	14
15	SPIRE INC (SR)	55.4%	0.0%	44.6%	100.0%	15
16	Average	49.5%	0.0%	50.5%	100.0%	16

ATMOS ENERGY CORP (ATO)

CAPITALIZATION STATISTICS
2016-2018
($ IN MILLIONS)

CAPITALIZATION STATISTICS

	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	3-Year Average
Amount of Capital Employed (Book Value)													
LT Borrowings	$ 3,068.67	$ 3,068.32	$ 3,067.89	$ 3,067.47	$ 3,067.05	$ 3,066.73	$ 2,564.62	$ 2,564.20	$ 2,438.78	$ 2,455.65	$ 2,455.56	$ 2,455.47	
Preferred Equity	-	-	-										
Common Equity + Minority Interest	4,769.95	4,759.55	4,721.35	4,563.62	3,898.67	3,901.71	3,834.86	3,698.98	3,463.06	3,466.72	3,344.57	3,272.11	
Total Permanent Capital	7,838.62	7,827.87	7,789.24	7,631.09	6,965.71	6,968.44	6,399.48	6,263.17	5,901.84	5,922.37	5,800.12	5,727.58	
Short Term Debt	575.78	244.78	129.60	336.82	447.75	258.57	670.61	940.75	829.81	670.47	626.93	763.24	
Total Capital Employed	$ 8,414.40	$ 8,072.64	$ 7,918.84	$ 7,967.91	$ 7,413.46	$ 7,227.02	$ 7,070.09	$ 7,203.92	$ 6,731.65	$ 6,592.84	$ 6,427.05	$ 6,490.82	
Capital Structure Ratios (Book Value)													
Based on Total Permanent Capital													
Long-Term Debt	39.15%	39.20%	39.39%	40.20%	44.03%	44.01%	40.08%	40.94%	41.32%	41.46%	42.34%	42.87%	**41.25%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	60.85%	60.80%	60.61%	59.80%	55.97%	55.99%	59.92%	59.06%	58.68%	58.54%	57.66%	57.13%	**58.75%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**
Based on Total Capital													
Total Debt, Including Short Term	43.31%	41.04%	40.38%	42.72%	47.41%	46.01%	45.76%	48.65%	48.56%	47.42%	47.96%	49.59%	**45.73%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	56.69%	58.96%	59.62%	57.28%	52.59%	53.99%	54.24%	51.35%	51.44%	52.58%	52.04%	50.41%	**54.27%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**

Source: Bloomberg

EXHIBIT NO. ___ (TKW-2)
SHEET 3 OF 8

CHESAPEAKE UTILITIES CORP (CPK)
CAPITALIZATION STATISTICS
2016-2018
($ IN MILLIONS)

CAPITALIZATION STATISTICS	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	
Amount of Capital Employed (Book Value)													
LT Borrowings	$ 327.96	$ 251.21	$ 251.57	$ 231.40	$ 206.82	$ 213.38	$ 213.71	$ 148.65	$ 149.05	$ 155.61	$ 155.94	$ 157.77	
Preferred Equity	-	-	-										
Common Equity + Minority Interest	518.44	508.30	507.99	505.24	486.29	463.82	461.68	460.83	446.09	438.30	379.55	374.25	
Total Permanent Capital	846.39	759.51	759.56	736.64	693.11	677.20	675.39	609.48	595.14	593.91	535.49	532.02	
Short Term Debt	294.46	268.29	235.29	229.11	250.97	203.10	145.59	199.33	209.87	154.49	180.04	172.74	
Total Capital Employed	$ 1,140.85	$ 1,027.80	$ 994.85	$ 965.75	$ 944.08	$ 880.30	$ 820.98	$ 808.81	$ 805.01	$ 748.40	$ 715.54	$ 704.76	
Capital Structure Ratios (Book Value)													**3-Year Average**
Based on Total Permanent Capital													
Long-Term Debt	38.75%	33.08%	33.12%	31.41%	29.84%	31.51%	31.64%	24.39%	25.05%	26.20%	29.12%	29.65%	**30.31%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	61.25%	66.92%	66.88%	68.59%	70.16%	68.49%	68.36%	75.61%	74.95%	73.80%	70.88%	70.35%	**69.69%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**
Based on Total Capital													
Total Debt, Including Short Term	54.56%	50.55%	48.94%	47.68%	48.49%	47.31%	43.77%	43.02%	44.59%	41.44%	46.96%	46.90%	**47.02%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	45.44%	49.45%	51.06%	52.32%	51.51%	52.69%	56.23%	56.98%	55.41%	58.56%	53.04%	53.10%	**52.98%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**

Source: Bloomberg

NEW JERSEY RESOURCES CORP (NJR)
CAPITALIZATION STATISTICS
2016-2018
($ IN MILLIONS)

CAPITALIZATION STATISTICS

	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	
Amount of Capital Employed (Book Value)													
LT Borrowings	$ 1,304.16	$ 1,260.69	$ 1,163.83	$ 1,167.35	$ 1,162.46	$ 1,084.00	$ 1,084.69	$ 1,123.51	$ 1,116.49	$ 979.16	$ 856.07	$ 859.16	
Preferred Equity	-	-	-										
Common Equity + Minority Interest	1,418.98	1,449.96	1,467.37	1,347.77	1,236.64	1,284.60	1,286.28	1,185.36	1,166.59	1,170.88	1,207.48	1,143.94	
Total Permanent Capital	2,723.14	2,710.66	2,631.20	2,515.12	2,399.10	2,368.60	2,370.97	2,308.88	2,283.08	2,150.05	2,063.56	2,003.11	
Short Term Debt	151.95	57.10	150.90	373.20	266.00	263.40	237.90	284.60	121.70	244.63	152.50	211.00	
Total Capital Employed	$ 2,875.09	$ 2,767.76	$ 2,782.10	$ 2,888.32	$ 2,665.10	$ 2,632.00	$ 2,608.87	$ 2,593.48	$ 2,404.78	$ 2,394.67	$ 2,216.06	$ 2,214.11	
Capital Structure Ratios (Book Value)													**3-Year**
Based on Total Permanent Capital													**Average**
Long-Term Debt	47.89%	46.51%	44.23%	46.41%	48.45%	45.77%	45.75%	48.66%	48.90%	45.54%	41.49%	42.89%	**46.04%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	52.11%	53.49%	55.77%	53.59%	51.55%	54.23%	54.25%	51.34%	51.10%	54.46%	58.51%	57.11%	**53.96%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**
Based on Total Capital													
Total Debt, Including Short Term	50.65%	47.61%	47.26%	53.34%	53.60%	51.19%	50.70%	54.29%	51.49%	51.10%	45.51%	48.33%	**50.42%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	49.35%	52.39%	52.74%	46.66%	46.40%	48.81%	49.30%	45.71%	48.51%	48.90%	54.49%	51.67%	**49.58%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**

Source: Bloomberg

NORTHWEST NATURAL GAS (NWN)

CAPITALIZATION STATISTICS
2016-2018
($ IN MILLIONS)

CAPITALIZATION STATISTICS

	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	
Amount of Capital Employed (Book Value)													
LT Borrowings	$ 736.24	$ 809.59	$ 758.68	$ 758.28	$ 779.89	$ 779.42	$ 720.11	$ 719.71	$ 719.32	$ 595.21	$ 595.03	$ 594.73	
Preferred Equity	-	-	-										
Common Equity + Minority Interest	762.63	737.58	759.53	772.21	742.78	846.68	865.43	874.62	850.50	779.20	800.00	806.96	
Total Permanent Capital	1,498.87	1,547.18	1,518.21	1,530.49	1,522.66	1,626.11	1,585.54	1,594.33	1,569.82	1,374.42	1,395.03	1,401.68	
Short Term Debt	217.62	100.50	47.10	50.00	54.20	-	-	-	53.30	194.90	152.80	164.90	
Total Capital Employed	$ 1,716.49	$ 1,647.68	$ 1,565.31	$ 1,580.49	$ 1,576.86	$ 1,626.11	$ 1,585.54	$ 1,594.33	$ 1,623.12	$ 1,569.32	$ 1,547.83	$ 1,566.58	
Capital Structure Ratios (Book Value)													**3-Year Average**
Based on Total Permanent Capital													
Long-Term Debt	49.12%	52.33%	49.97%	49.55%	51.22%	47.93%	45.42%	45.14%	45.82%	43.31%	42.65%	42.43%	**47.07%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	50.88%	47.67%	50.03%	50.45%	48.78%	52.07%	54.58%	54.86%	54.18%	56.69%	57.35%	57.57%	**52.93%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**
Based on Total Capital													
Total Debt, Including Short Term	55.57%	55.24%	51.48%	51.14%	52.90%	47.93%	45.42%	45.14%	47.60%	50.35%	48.31%	48.49%	**49.96%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	44.43%	44.76%	48.52%	48.86%	47.10%	52.07%	54.58%	54.86%	52.40%	49.65%	51.69%	51.51%	**50.04%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**

Source: Bloomberg

ONE GAS INC (OGS)
CAPITALIZATION STATISTICS
2016-2018
($ IN MILLIONS)

CAPITALIZATION STATISTICS

	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	3-Year Average
Amount of Capital Employed (Book Value)													
LT Borrowings	$ 1,285.48	$ 1,193.89	$ 1,193.68	$ 1,193.47	$ 1,193.26	$ 1,193.05	$ 1,192.85	$ 1,192.65	$ 1,192.45	$ 1,192.26	$ 1,192.06	$ 1,191.86	
Preferred Equity	-	-	-										
Common Equity + Minority Interest	2,042.66	2,016.62	2,022.34	2,020.95	1,960.21	1,931.99	1,933.30	1,944.58	1,888.28	1,862.34	1,875.59	1,867.19	
Total Permanent Capital	3,328.14	3,210.51	3,216.02	3,214.42	3,153.47	3,125.04	3,126.14	3,137.23	3,080.73	3,054.60	3,067.65	3,059.05	
Short Term Debt	299.50	276.00	185.00	282.61	357.22	174.00	79.00	85.40	145.00	41.00	-	-	
Total Capital Employed	$ 3,627.64	$ 3,486.51	$ 3,401.02	$ 3,497.03	$ 3,510.68	$ 3,299.04	$ 3,205.14	$ 3,222.63	$ 3,225.73	$ 3,095.60	$ 3,067.65	$ 3,059.05	
Capital Structure Ratios (Book Value)													
Based on Total Permanent Capital													
Long-Term Debt	38.62%	37.19%	37.12%	37.13%	37.84%	38.18%	38.16%	38.02%	38.71%	39.03%	38.86%	38.96%	**38.15%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	61.38%	62.81%	62.88%	62.87%	62.16%	61.82%	61.84%	61.98%	61.29%	60.97%	61.14%	61.04%	**61.85%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**
Based on Total Capital													
Total Debt, Including Short Term	43.69%	42.16%	40.54%	42.21%	44.16%	41.44%	39.68%	39.66%	41.46%	39.84%	38.86%	38.96%	**41.06%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	56.31%	57.84%	59.46%	57.79%	55.84%	58.56%	60.32%	60.34%	58.54%	60.16%	61.14%	61.04%	**58.94%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**

Source: Bloomberg

SOUTH JERSEY INDUSTRIES, INC (SJI)

CAPITALIZATION STATISTICS
2016-2018
($ IN MILLIONS)

CAPITALIZATION STATISTICS	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	3-Year Average
Amount of Capital Employed (Book Value)													
LT Borrowings	$ 2,840.77	$ 2,763.73	$ 2,772.61	$ 1,238.56	$ 1,186.81	$ 1,191.23	$ 1,082.59	$ 1,111.21	$ 1,039.91	$ 1,040.61	$ 1,075.69	$ 1,075.57	
Preferred Equity	-	-	-										
Common Equity + Minority Interest	1,267.02	1,234.83	1,303.72	1,281.50	1,192.41	1,221.35	1,279.25	1,307.90	1,289.24	1,267.38	1,277.55	1,093.44	
Total Permanent Capital	4,107.79	3,998.57	4,076.33	2,520.06	2,379.22	2,412.58	2,361.84	2,419.11	2,329.15	2,307.99	2,353.24	2,169.01	
Short Term Debt	270.50	421.40	336.40	248.10	346.40	280.10	296.30	205.10	296.10	230.20	145.40	339.50	
Total Capital Employed	$ 4,378.29	$ 4,419.97	$ 4,412.73	$ 2,768.16	$ 2,725.62	$ 2,692.68	$ 2,658.14	$ 2,624.21	$ 2,625.25	$ 2,538.19	$ 2,498.64	$ 2,508.51	
Capital Structure Ratios (Book Value)													
Based on Total Permanent Capital													
Long-Term Debt	69.16%	69.12%	68.02%	49.15%	49.88%	49.38%	45.84%	45.93%	44.65%	45.09%	45.71%	49.59%	**52.63%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	30.84%	30.88%	31.98%	50.85%	50.12%	50.62%	54.16%	54.07%	55.35%	54.91%	54.29%	50.41%	**47.37%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**
Based on Total Capital													
Total Debt, Including Short Term	71.06%	72.06%	70.46%	53.71%	56.25%	54.64%	51.87%	50.16%	50.89%	50.07%	48.87%	56.41%	**57.20%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	28.94%	27.94%	29.54%	46.29%	43.75%	45.36%	48.13%	49.84%	49.11%	49.93%	51.13%	43.59%	**42.80%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**

Source: Bloomberg

SPIRE INC (SR)

CAPITALIZATION AND FINANCIAL STATISTICS
2016-2018
($ IN MILLIONS)

CAPITALIZATION STATISTICS

	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	
Amount of Capital Employed (Book Value)													
LT Borrowings	$ 2,075.60	$ 2,180.00	$ 2,179.40	$ 2,135.50	$ 2,095.00	$ 1,925.30	$ 1,925.30	$ 2,071.30	$ 2,070.70	$ 1,839.80	$ 1,851.60	$ 1,851.50	
Preferred Equity	-	-	-										
Common Equity + Minority Interest	2,263.30	2,314.20	2,160.00	2,085.70	1,991.30	2,028.20	1,883.00	1,796.70	1,768.20	1,802.40	1,681.40	1,600.30	
Total Permanent Capital	4,338.90	4,494.20	4,339.40	4,221.20	4,086.30	3,953.50	3,808.30	3,868.00	3,838.90	3,642.20	3,533.00	3,451.80	
Short Term Debt	553.60	191.00	391.70	583.60	477.30	450.70	567.40	506.40	398.70	97.60	253.60	377.10	
Total Capital Employed	$ 4,892.50	$ 4,685.20	$ 4,731.10	$ 4,804.80	$ 4,563.60	$ 4,404.20	$ 4,375.70	$ 4,374.40	$ 4,237.60	$ 3,739.80	$ 3,786.60	$ 3,828.90	
Capital Structure Ratios (Book Value)													**3-Year Average**
Based on Total Permanent Capital													
Long-Term Debt	47.84%	48.51%	50.22%	50.59%	51.27%	48.70%	50.56%	53.55%	53.94%	50.51%	52.41%	53.64%	**50.98%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	52.16%	51.49%	49.78%	49.41%	48.73%	51.30%	49.44%	46.45%	46.06%	49.49%	47.59%	46.36%	**49.02%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**
Based on Total Capital													
Total Debt, Including Short Term	53.74%	50.61%	54.34%	56.59%	56.37%	53.95%	56.97%	58.93%	58.27%	51.80%	55.60%	58.20%	**55.45%**
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.00%**
Common Equity	46.26%	49.39%	45.66%	43.41%	43.63%	46.05%	43.03%	41.07%	41.73%	48.20%	44.40%	41.80%	**44.55%**
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	**100.00%**

Source: Bloomberg

SOUTHWEST GAS CORPORATION
FVROR EXAMPLE - REVENUE REQUIREMENT

This compares the revenue requirement computed for the existing and incremental FVRB compared to the revenue requirement if the Company had filed a new rate general rate case that included the new investment, holding all else constant.

Surcharge on using incremental FVROR

Line No.	Type of Rate Base	OCRB	RCND	FVRB	Weight	FVRB/OCRB	WACC	FVROR	Pretax ROR	Revenue Requirement	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
1	Existing Rate Base	$ 1,324,902,393	$ 2,277,227,765	$ 1,801,065,079	94.74%	1.36	7.42%	5.71%	8.11%	$ 146,048,399	1
2	Incremental Rate Base	100,000,000	100,000,000	100,000,000	5.26%	1.00	7.42%	7.42%	10.48%	10,481,000	2
3	Total Rate Base	$ 1,424,902,393	$ 2,377,227,765	$ 1,901,065,079	100.00%	1.33	7.42%	5.80%	8.23%	$ 156,529,399	3
	File a new general rate case										
4	Total Rate Base	$ 1,424,902,393	$ 2,377,227,765	$ 1,901,065,079	100.00%	1.33	7.42%	5.80%	8.23%	$ 156,529,399	4
5									Sufficiency / (Deficiency) =	$ -	5

Surcharge on using authorized FVROR

Line No.	Type of Rate Base	OCRB	RCND	FVRB	Weight	FVRB/OCRB	WACC	FVROR	Pretax ROR	Revenue Requirement	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
6	Existing Rate Base	$ 1,324,902,393	$ 2,277,227,765	$ 1,801,065,079	94.74%	1.36	7.42%	5.71%	8.11%	$ 146,048,399	6
7	Incremental Rate Base	100,000,000	100,000,000	100,000,000	5.26%	1.00	7.42%	5.71%	8.11%	8,109,002	7
8	Total Rate Base	$ 1,424,902,393	$ 2,377,227,765	$ 1,901,065,079	100.00%	1.33	7.42%	5.80%	8.11%	$ 154,157,401	8
	File a new general rate case										
9	Total Rate Base	$ 1,424,902,393	$ 2,377,227,765	$ 1,901,065,079	100.00%	1.33	7.42%	5.80%	8.23%	$ 156,529,399	9
10									Sufficiency / (Deficiency) =	**$ (2,371,998)**	10

EXHIBIT NO. ___ (TKW-4)
SHEET 1 OF 2

SOUTHWEST GAS CORPORATION
PROXY GROUP OF VALUE LINE GAS DISTRIBUTION COMPANIES
PRETAX RATES OF RETURN - CAPITAL RECOVERY MECHANISMS

Line No.	Company	Parent	State	Capital Investment	Name	Equity Ratio	LT Debt Ratio	ST Debt Ratio	ROE	LT Debt Cost	ST Debt Cost	WACC	FIT	SIT	Pretax ROR	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
1	Atmos Energy	ATO	Colorado	✓	System Safety and Integrity Rider	55.58%	44.42%	0.00%	9.45%	5.17%	0.00%	7.55%	21.00%	4.63%	9.27%	1
2	Atmos Energy	ATO	Kansas	✓	Gas System Reliability Surcharge										9.54%	2
3	Atmos Energy	ATO	Kentucky	✓	Pipeline Replacement Rider	52.57%	43.95%	3.48%	9.70%	5.09%	1.66%	7.39%	21.00%	5.00%	9.09%	3
4	Atmos Energy	ATO	Louisiana	✓	Rate Stabilization Clause	55.96%	44.04%	0.00%	9.80%	4.68%	0.00%	7.55%	21.00%	8.00%	9.61%	4
5	Atmos Energy	ATO	Mississippi	✓	System Integrity Rider	52.50%	46.28%	1.22%	9.92%	5.13%	1.82%	7.60%	21.00%	5.00%	9.34%	5
6	Atmos Energy	ATO	Tennessee	✓	Annual Review Mechanism	51.40%	40.44%	8.16%	9.80%	5.18%	1.46%	7.25%	21.00%	6.50%	9.03%	6
7	Atmos Energy	ATO	Texas	✓	Gas Reliability Infrastructure Program	51.69%	48.31%	0.00%	10.50%	6.50%	0.00%	8.57%	21.00%	0.00%	10.01%	7
8	Atmos Energy	ATO	Virginia	✓	Infrastructure Reliability and Replacement Adjustment	58.21%	36.98%	4.82%	9.20%	5.35%	1.96%	7.43%	21.00%	6.00%	9.28%	8
9	Chesapeake Utilities	CPK	Delaware													9
10	Chesapeake Utilities	CPK	Maryland													10
11	Florida Public Utilities Company	CPK	Florida	✓	Gas Reliability Infrastructure Program	46.27%			10.85%			6.60%	21.00%	5.50%	8.30%	11
12	New Jersey Natural Gas	NJR	New Jersey	✓	Reinvestment in System Enhancement Program	52.50%	45.07%	2.43%	9.75%	3.89%	1.00%	6.90%	21.00%	9.00%	8.90%	12
13	Northwest Natural Gas	NWN	Oregon	✓	System Integrity Program	50.00%	50.00%	0.00%	9.50%	6.06%	0.00%	7.78%	21.00%	7.60%	9.54%	13
14	Northwest Natural Gas	NWN	Washington													14
15	Kansas Gas Service	OGS	Kansas	✓	Gas System Reliability Surcharge										8.33%	15
16	Oklahoma Natural Gas	OGS	Oklahoma	✓	Performance Based Rate Change Plan	58.00%	42.00%	0.00%	9.50%	3.95%	0.00%	7.17%	21.00%	6.00%	9.08%	16
17	Texas Gas Service	OGS	Texas	✓	Gas Reliability Infrastructure Program	60.12%	39.88%	0.00%	9.50%	3.95%	0.00%	7.28%	21.00%	0.00%	8.80%	17
18	Alabama Gas Corporation	SR	Alabama	✓	Rate Stabilization and Equalization Plan										[1]	18
19	Spire Gulf Inc. (Mobile Gas Corporation)	SR	Alabama	✓	Rate Stabilization and Equalization Plan										[1]	19
20	Spire Missouri East	SR	Missouri	✓	Infrastructure System Replacement Surcharge	54.20%	45.80%	0.00%	9.80%	4.12%	0.00%	7.20%	21.00%	6.25%	9.06%	20
21	Spire Missouri West	SR	Missouri	✓	Infrastructure System Replacement Surcharge	54.20%	45.80%	0.00%	9.80%	4.12%	0.00%	7.20%	21.00%	6.25%	9.06%	21
22	Elizabethtown Gas	SJI	New Jersey													22
23	South Jersey Gas	SJI	New Jersey	✓	Storm Hardening and Reliability Program	52.50%	47.50%	0.00%	9.60%	3.70%	0.00%	6.80%	21.00%	9.00%	8.77%	23
24														Mean	9.12%	24
25														Median	9.08%	25
26														Maximum	10.01%	26
27														Minimum	8.30%	27

[1] Infrastructure cost recovery under perfromance based rate mechanism

SOUTHWEST GAS CORPORATION
PRETAX RATES OF RETURN

INCREMENTAL FVROR

Line No.	Capital (a)	$ (b)	% (c)	Cost (d)	WACC Weighted Cost (e)	Line No.
1	Common Equity	$ 51,700,000	51.70%	9.50%	4.91%	1
2	Long-Term Debt	48,300,000	48.30%	5.20%	2.51%	2
3	FRVB Increment	-	0.00%	0.93%	0.00%	3
4	Total Capital	$ 100,000,000	100.00%		7.42%	4
5		Gross-Up Factor	1.3336		$\boxed{9.06\%}$	5

FVRB - FVROR - GRC

Line No.	Capital (a)	$ (b)	% (c)	Cost (d)	FVROR Weighted Cost (e)	Line No.
6	Common Equity	$ 684,974,537	38.03%	9.50%	3.61%	6
7	Long-Term Debt	639,927,856	35.53%	5.20%	1.85%	7
8	FRVB Increment	476,162,686	26.44%	0.93%	0.25%	8
9	Total Capital	$ 1,801,065,079	100.00%		5.71%	9
10		Gross-Up Factor	1.3336		$\boxed{6.99\%}$	10

Tab 10

Direct Testimony
of
Robert B. Hevert

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-19-0055

PREPARED DIRECT TESTIMONY
OF
ROBERT B. HEVERT

ON BEHALF OF
SOUTHWEST GAS CORPORATION

MAY 1, 2019

Table of Contents
of
Prepared Direct Testimony
of
ROBERT B. HEVERT

Appendix C	Summary of Qualifications of Robert B. Hevert
Exhibit No._(RBH-1)	Constant Growth Discounted Cash Flow Model
Exhibit No._(RBH-2)	Retention Growth Estimate
Exhibit No._(RBH-3)	*Ex-Ante* Market Risk Premium
Exhibit No._(RBH-4)	Beta Coefficients
Exhibit No._(RBH-5)	Capital Asset Pricing Model Results
Exhibit No._(RBH-6)	Bond Yield Plus Risk Premium
Exhibit No._(RBH-7)	Expected Earnings Analysis
Exhibit No._(RBH-8)	Summary of Adjustment Clauses / Alternative Regulation
Exhibit No._(RBH-9)	Flotation Costs
Exhibit No._(RBH-10)	Calculation of Fair Value Rate Base and Rate of Return
Exhibit No._(RBH-11)	Credit Ratings – Proxy Group Results
Exhibit No._(RBH-12)	Moody's Regulatory Framework – Proxy Group Results

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
ROBERT B. HEVERT

I. INTRODUCTION

Q. 1 Please state your name, affiliation and business address.

A. 1 My name is Robert B. Hevert. I am a Partner of ScottMadden, Inc. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q. 2 On whose behalf are you submitting this testimony?

A. 2 I am submitting this direct testimony ("Direct Testimony") before the Arizona Corporation Commission (the "Commission") on behalf of Southwest Gas Corporation ("Southwest Gas" or the "Company").

Q. 3 Please describe your educational background.

A. 3 I hold a Bachelor's degree in Business and Economics from the University of Delaware, and an MBA with a concentration in Finance from the University of Massachusetts. I also hold the Chartered Financial Analyst designation.

Q. 4 Please describe your experience in the energy and utility industries.

A. 4 I have worked in regulated industries for more than 30 years, having served as an executive and manager with consulting firms, a financial officer of a publicly traded natural gas utility, and an analyst at a telecommunications utility. In my role as a consultant, I have advised numerous energy and utility clients on a wide range of financial and economic issues, including corporate and asset-based transactions, asset and enterprise valuation, transaction due diligence, and strategic matters. As an expert witness, I have provided testimony in more than 250 proceedings regarding various financial and regulatory matters before numerous state utility regulatory agencies, the Federal Energy Regulatory Commission, Federal District Court, and the Alberta Utilities Commission. A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included in Appendix C to my Direct Testimony.

II. SUMMARY OF EXHIBITS

Q. 5 Do you sponsor any exhibits in support of your testimony?

A. 5 My conclusions are supported by the data and analyses presented in Exhibit No._(RBH-1) through Exhibit No._(RBH-12), which have been prepared by me or under my direction:

- Exhibit No._(RBH-1) presents my Constant Growth Discounted Cash Flow ("DCF") model results;
- Exhibit No._(RBH-2) presents the derivation of the proxy group retention growth rate applicable to the Constant Growth DCF model;
- Exhibit No._(RBH-3) presents the derivation of the Market Risk Premium for use in the Capital Asset Pricing Model ("CAPM");
- Exhibit No._(RBH-4) presents the Value Line and Bloomberg Financial Beta coefficients for the proxy group for use in the CAPM;
- Exhibit No._(RBH-5) presents my CAPM results;
- Exhibit No._(RBH-6) presents my Bond Yield Plus Risk Premium analysis;
- Exhibit No._(RBH-7) presents my Expected Earnings analysis;

- Exhibit No._(RBH-8) presents regulatory mechanisms in place for the Company's proxy group;
- Exhibit No._(RBH-9) presents the derivation of flotation costs applicable to the Company's indicated Cost of Equity;
- Exhibit No._(RBH-10) presents the calculation of the fair value rate base and fair value rate of return;
- Exhibit No._(RBH-11) presents credit ratings of the proxy group compared to the Company; and
- Exhibit No._(RBH-12) presents Moody's regulatory framework applied to the proxy group and the Company.

III. PURPOSE AND OVERVIEW OF TESTIMONY

Q. 6 What is the purpose of your Direct Testimony?

A. 6 The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding the Company's return on equity ("ROE").[1] My analyses and conclusions are supported by the data presented in Exhibit No._(RBH-1) through Exhibit No._(RBH-12).

Q. 7 Please provide a brief overview of the analyses that led to your ROE recommendation.

A. 7 Because all models are subject to assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. I therefore applied four widely accepted approaches to develop my ROE recommendation: (1) the Constant Growth form of the DCF model; (2) the CAPM;

[1] Throughout my Direct Testimony, I interchangeably use the terms "ROE" and "Cost of Equity."

(3) the Bond Yield Plus Risk Premium approach; and (4) the Expected Earnings method. Those analyses indicate that the Company's Cost of Equity is in the range of 10.00 percent to 10.75 percent.

In addition to the methods noted above, I reviewed the Company's capital spending plan and regulatory recovery mechanisms, including its decoupling mechanism; considered evolving capital market and business conditions, including changes in Federal monetary policy and increases in current and projected government bond yields on the utility industry; and calculated the cost of issuing additional shares of common stock. Although I did not make explicit adjustments to my ROE estimates for those factors, I did consider them in determining where the Company's Cost of Equity falls within the range of analytical results.

My analyses recognize that estimating the Cost of Equity is an empirical, but not an entirely mathematical exercise; it relies on both quantitative and qualitative data and analyses, all of which are used to inform the judgment that inevitably must be applied. I therefore considered my analytical results in the context of such Company-specific and general capital market factors as those summarized above. Based on the quantitative and qualitative analyses discussed throughout my Direct Testimony, I find 10.30 percent to be a reasonable and appropriate estimate of the Company's Cost of Equity.

No single model is more reliable than all others under all market conditions, and all require the use of reasoned judgment in their application, and in interpreting their results. Therefore, the results of each ROE model must be assessed in the context of current and expected capital market conditions, and relative to other appropriate benchmarks. In developing my recommendation, I recognized that the low and high ends of the range of results (set by the low end of the range of Constant Growth DCF model results, and the high end of the range of CAPM results, respectively) are not likely to be reasonable estimates of the Company's Cost of Equity.

Q. 8 Please now summarize the results of the four methods discussed above, and how they contributed to your ROE recommendation.

A. 8 The range of results produced by the four approaches noted above are as follows:

- The Discounted Cash Flow method indicates an ROE in the range of approximately 9.60 percent to 12.40 percent (please refer to Table 2);[2]
- Giving less weight to the highest and lowest results, the CAPM model suggests an ROE in the range of approximately 10.25 percent to 12.50 percent (please refer to Table 3);[3]
- The Bond Yield Plus Risk Premium approach suggests an ROE in the range of approximately 9.90 percent to 10.10 percent (please refer to Table 4);[4] and
- The Expected Earnings analysis suggests an ROE in the range of approximately 10.10 percent to 12.10 percent (please refer to Table 5).[5]

Based on those estimates, I recommend an ROE in the range of 10.00 percent to 10.75 percent and, within that range, recommend an ROE of 10.30 percent.

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[2] As discussed above, my estimate of the indicated range is narrower than the overall range of model results. Moreover, for the reasons discussed below, I find the underlying assumptions of the DCF model inconsistent with the current capital market and believe the model's results should be viewed with caution.

[3] As discussed above, my estimate of the indicated range is narrower than the overall range of model results.

[4] Results rounded.

[5] Results rounded.

As discussed in more detail throughout the balance of my Direct Testimony, my conclusions and recommendations reflect the following considerations:

- Widespread expectations for continuing increases in interest rates, as revealed in both market data and economists' consensus projections, which weigh in the evaluation of the DCF, CAPM, Bond Yield Plus Risk Premium, and Expected Earnings results;
- The Company's capital expenditure plans and cost recovery mechanisms which affect its ability to earn its authorized Return on Equity;
- The effect of flotation costs, which represent a permanent reduction to the capital needed to support the assets required to provide safe and reliable utility service; and
- The need to maintain the financial profile required to access capital at reasonable rates, even during unstable capital markets.

Q. 9 Are there other factors that should be considered in determining the weight given to the methods and results summarized above?

A. 9 Yes. All models used to estimate the Cost of Equity are subject to certain assumptions, which may become more, or less, relevant as market conditions and market data change. An important consideration is the consistency of each model's underlying assumptions with current and expected market conditions, and the reasonableness of its results relative to observable benchmarks. For example, the Constant Growth DCF model assumes the estimated Cost of Equity will remain constant in perpetuity. We know, however, that the Federal Reserve has begun to "normalize" monetary policy, such that the conditions supporting current ROE estimates will not persist in the long-run. Because that model does not allow us to incorporate such important factors, or to reflect the expected risk associated with changing market conditions, its results should be viewed with caution.

Risk Premium-based methods (such as the Capital Asset Pricing Model), on the other hand, provide a measure of risk and have the benefit of directly considering investors' expectations regarding future market returns. Other Risk Premium approaches (*e.g.*, the Bond Yield Plus Risk Premium approach) reflect the well-documented finding that the Cost of Equity does not move in lock-step with interest rates. For example, at times interest rates fall because investors are so risk averse they would rather accept a very modest return on Treasury securities than take on the risk of equity ownership. In such circumstances, low interest rates suggest an increasing, not a decreasing, Cost of Equity. The Expected Earnings analysis calculates the Cost of Equity based on the opportunity cost of the return of an alternative investment in an enterprise with similar risk, and corroborates the findings from the DCF, CAPM and Bond Yield Plus Risk Premium approaches. Because those methods provide different perspectives on investor return requirements, their use in combination enables a more comprehensive assessment of the Cost of Equity.

In summary, each model has strengths and weaknesses and it is important to recognize those differences in estimating the Cost of Equity. In my view, the Constant Growth DCF model, which requires constant assumptions, inputs, and results in perpetuity, should be considered with some caution.[6] Risk

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[6] Other jurisdictions have noted similar conclusions. *See, for example*, *Martha Coakley v. Bangor Hydro-Electric Company,* Opinion No. 531, 147 FERC ¶ 61,234 (2014), *Order On Paper Hearing* Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), and *Order On Rehearing* Opinion No. 531-B, 150 FERC ¶ 61,165 (2015); Massachusetts Department of Public Utilities, D.P.U. 13-90, *Petition of Fitchburg Gas and Electric*

Premium-based methods, which provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the Cost of Equity, may be given somewhat more consideration. And, as noted earlier, the Expected Earnings method provides a method of corroborating other model results. With those considerations in mind, I believe my recommendation reasonably reflects investors' return requirements in the current market environment.

Q. 10 How is the remainder of your Direct Testimony organized?

A. 10 The remainder of my Direct Testimony is organized as follows:

Section IV – Discusses the regulatory guidelines and financial considerations pertinent to the development of the cost of capital;

Section V – Explains my selection of the proxy group used to develop my analytical results;

Section VI – Explains my analyses and the analytical bases for my ROE recommendation;

Section VII – Provides a discussion of business risks and other considerations that have a direct bearing on the Company's Cost of Equity;

Section VIII – Highlights the current capital market conditions and their effect on the Company's Cost of Equity;

Section IX – Discusses the fair value rate base;

Light Company (Electric Division) d/b/a Unitil, May 30, 2014, at 219; *Formal Case No. 1093, In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's Existing Rates and Charges for Gas Service*, Before the Public Service Commission of the District of Columbia, Order No. 17132, May 15, 2013, at 17-18, 20. Also, an article recently published by Bloomberg notes the ultralow interest rate environment has "wrought havoc" on the DCF model. *See*, Kawa, Luke, "A Critical Idea in Valuing Stocks Is Being Made Obsolete by Low Rates," Bloomberg Business, October 13, 2016. http://www.bloomberg.com/news/articles/2016-10-13/a-critical-idea-in-valuing-stocks-is-being-madeobsolete-by-low-rates.

<u>Section X</u> – Derives the fair value rate of return; and

<u>Section XI</u> – Summarizes my conclusions and recommendations.

I also included Appendices A and B, which explain in detail the selection criteria used for my utility proxy group, and the analysis and inputs for each of my Cost of Equity models.

IV. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS

Q. 11 Before addressing the specific aspects of this proceeding, please provide an overview of the issues surrounding the Cost of Equity in regulatory proceedings, generally.

A. 11 In general terms, the Cost of Equity is the return investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return they *expect* is equal to, or greater than, the return they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity" as measures of those costs; together, they are referred to as the "Cost of Capital."

The Cost of Capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset, whether debt or equity securities, implies a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk. In that important respect, the returns required by debt and equity investors represent a cost to the Company.

Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate or yield on debt securities.[7] The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. Because equity investors bear the "residual risk," they take greater risks and require higher returns than debt holders. In that basic sense, equity and debt investors differ: they invest in different securities, face different risks, and require different returns.

Whereas the Cost of Debt may be directly observed, the Cost of Equity must be estimated based on market data and various financial models. As discussed throughout my Direct Testimony, each model is subject to specific assumptions, which may become more, or less, applicable as market conditions change. In addition, because the Cost of Equity is premised on opportunity costs, the models typically are applied to a group of "comparable" or "proxy" companies. The choice of models (including their inputs), the selection of proxy companies, and the interpretation of the model results all require the application of reasoned judgment. That judgment should consider data and information that is not necessarily included in the models themselves. In the end, the estimated Cost of Equity should reflect the return that investors require in light of the subject

[7] The observed interest rate may be adjusted to reflect issuance costs.

company's risks, and the returns available on comparable investments.

Q. 12 Please provide a brief summary of the guidelines established by the United States Supreme Court (the "Court") for the purpose of determining the Return on Equity.

A. 12 The Court established the guiding principles for establishing a fair return for capital in two cases: (1) Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia ("*Bluefield*");[8] and (2) Federal Power Comm'n v. Hope Natural Gas Co. ("*Hope*").[9] In those cases, the Court recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

Q. 13 Has the Commission provided similar guidance?

A. 13 Yes, the Commission has noted that under the Arizona Constitution, a public utility is entitled to a fair return on the fair value of its property devoted to public uses. The Commission is required to find the fair value of the utility's property and to use that value to establish just and reasonable rates.[10]

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[8] *See,* Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679, 692-93 (1923).

[9] *See,* Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

[10] *See,* Arizona Corporation Commission Order No. W-02113A-04-0_16, Chaparral City Water Company, February 13, 2007, at 11. References Ariz. Water co., 85 Ariz. at 203,335, P.2d at 415.

Q. 14 Aside from those long-held standards, why is it important for a utility to be allowed the opportunity to earn a return adequate to attract equity capital at reasonable terms?

A. 14 A return adequate to attract capital at reasonable terms enables the utility to provide safe and reliable service while maintaining its financial integrity. In keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. The consequence of the Commission's order in this case, therefore, should be to provide Southwest Gas the opportunity to earn a Return on Equity that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. To the extent Southwest Gas is provided a reasonable opportunity to earn its market-based Cost of Equity, neither customers nor shareholders should be disadvantaged. In fact, a return adequate to attract capital at reasonable terms enables the Company to provide safe, reliable natural gas utility service while maintaining its financial integrity.

Q. 15 How is the Cost of Equity estimated in regulatory proceedings?

A. 15 As noted earlier (and as discussed in more detail later in my Direct Testimony), the Cost of Equity is estimated by the use of various financial models. By their nature, those models produce a range of results from which the ROE is determined. That determination must be based on a comprehensive review of relevant data and information; it does not necessarily lend itself to a strict mathematical solution. The key consideration in determining the ROE is to ensure the overall analysis reasonably reflects investors' view of the financial markets in general, and the subject company (in the context of the proxy companies), in particular.

The use of multiple methods, and the consideration given to them, recently was addressed by the Federal Energy Regulatory Commission ("FERC"). In its November 15, 2018 *Order Directing Briefs,* FERC found that "in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE".[11] In its October 16, 2018 *Order Directing Briefs*, FERC found that although it "previously relied solely on the DCF model to produce the evidentiary zone of reasonableness…", it is "…concerned that relying on that methodology alone will not produce just and reasonable results."[12] As FERC explained, because the Cost of Equity depends on what the market expects, it is important to understand "how investors analyze and compare their investment opportunities."[13] FERC also explained that, although certain investors may give some weight to the DCF approach, other investors "place greater weight on one or more of the other methods…"[14] Those methods include the CAPM, the Risk Premium method and the Expected Earnings method, all of which I have applied in this proceeding.

In summary, practitioners, academics, and regulatory commissions recognize that financial models are tools to be used in the ROE estimation process, and the strict adherence to any single approach, or to the specific results

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[11] Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.

[12] Docket No. EL11-66-001, *et al*., *Order Directing Briefs*, 165 FERC ¶ 61,030 (October 16, 2018) at para. 30.

[13] *Id*., at para. 33.

[14] *Id*., at para. 35. *See*, generally, Docket No. PL19-4-000, *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, March 21, 2019.

of any single approach, can lead to flawed or misleading conclusions. That position is consistent with the *Hope* and *Bluefield* principle that it is the analytical result, as opposed to the method employed, that is controlling in arriving at ROE determinations. A reasonable ROE estimate therefore considers multiple methods, and the reasonableness of their individual and collective results in the context of observable, relevant market information.

V. PROXY GROUP SELECTION

Q. 16 As a preliminary matter, why is it necessary to select a group of proxy companies to determine the Cost of Equity for Southwest Gas?

A. 16 First, it is important to bear in mind that the Cost of Equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. According to financial theory, the value of a given company is equal to the aggregate market value of its constituent business units. The value of the individual business units reflects the risks and opportunities inherent in the business sectors in which those units operate. In this proceeding, we are focused on estimating the Cost of Equity for the Company's Arizona operations. Because the ROE is a market-based concept and given the fact that the Company's jurisdictional operations within Arizona are not a separate entity with its own stock price, it is necessary to establish a group of companies that are both publicly traded and comparable to the Company to serve as its "proxy" for purposes of the ROE estimation process.

Even if the Company's Arizona jurisdictional assets did constitute the entirety of the parent company's operations, it is possible that transitory events could bias its market value in one way or another over a given period of time. A significant benefit of using a proxy group is that it serves to moderate the effects of anomalous, temporary events associated with any one company.

Q. 17 Does the selection of a proxy group suggest that analytical results will be tightly clustered around average (i.e., mean) results?

A. 17 No. For example, the DCF approach calculates the Cost of Equity using the expected dividend yield and projected growth. Despite the care taken to ensure risk comparability, market expectations with respect to future risks and growth opportunities will vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range.[15] An ongoing issue is how to best estimate the market-required ROE from within that range. That determination necessarily must consider a wide range of both empirical and qualitative information.

Q. 18 Please provide a summary profile of Southwest Gas.

A. 18 Southwest Gas provides natural gas distribution service to 2,047,000 customers in Arizona, Nevada and California. Of this total customer base, the Company's Arizona operations serves 1,090,000 customers.[16] Southwest Gas currently has senior unsecured ratings of A3 (outlook: Stable), BBB+ (outlook: Negative) and A (outlook: Stable) from Moody's Investor Service, Standard & Poor's Rating Services and Fitch Ratings, respectively.[17]

Q. 19 What companies are included in your proxy group?

A. 19 The criteria discussed in Appendix A resulted in a proxy group of the following seven companies:

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[15] In Appendix B, I provide more substantive descriptions of the models used to estimate the ROE.
[16] *See,* Southwest Gas Holdings 2018 Year End Earnings Conference Call – Slide Presentation at http://investors.swgasholdings.com/phoenix.zhtml?c=117697&p=irol-calendarPast.
[17] Source: Bloomberg Professional.

Table 1: Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
Chesapeake Utilities Corporation[18]	CPK
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Spire Inc.	SR

VI. COST OF EQUITY ESTIMATION

Q. 20 Please briefly discuss the ROE in the context of the regulated rate of return.

A. 20 Regulated utilities primarily use common stock and long-term debt to finance their capital investments. The overall rate of return ("ROR") weighs the costs of the individual sources of capital by their respective book values. While the cost of debt can be directly observed, the Cost of Equity is market-based and, therefore, must be estimated based on observable market information.

Q. 21 How is the required ROE determined?

A. 21 Because the Cost of Equity is not directly observable, it must be estimated based on both quantitative and qualitative information. Although several models have been developed for that purpose, all are subject to limiting assumptions or other constraints. Consequently, many finance texts recommend using multiple approaches to estimate the Cost of Equity.[19] When faced with the task of

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[18] Even though Chesapeake Utilities Corp. is not publicly rated by S&P, its Value Line Financial Strength Rating of B++ is comparable to the rest of the proxy group. CPK also has an National Association of Insurance Commissioners (NAIC) rating of "NAIC 1," which is equivalent to ratings in the "A" category for both Moody's and Standard & Poor's. *See* Chesapeake Utilities Corporation, Northeast Road Show, January 2018, at 16; National Association of Insurance Commissioners, CRP Credit Rating Equivalent to SVO Designations, November 2017.

[19] *See, for example,* Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341, and Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed., 2000, at 214.

estimating the Cost of Equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed and, therefore, rely on multiple analytical approaches.

As discussed earlier, because no individual model is more reliable than all others under all market conditions, it is both prudent and appropriate to use multiple methods. I therefore applied the Constant Growth DCF model, the Capital Asset Pricing Model, the Bond Yield Plus Risk Premium, and the Expected Earnings approach.

Q. 22 Why did you select those four models?

A. 22 I did so for two reasons. First, because the purpose of ROE analyses is to estimate the return investors require, it is important to use the models on which they rely. As discussed in Appendix B, the models I apply are commonly used in practice. Second, the models focus on different aspects of return requirements, and provide different insights to investors' views of risk and return. Using multiple models provides a broader, and therefore a more reliable perspective on investors' return requirements.

Q. 23 Please briefly describe the Constant Growth DCF model.

A. 23 The Constant Growth DCF approach defines the Cost of Equity as the sum of (1) the expected dividend yield, and (2) expected long-term growth. The expected dividend yield generally equals the expected annual dividend divided by the current stock price, and the growth rate is based on analysts' expectations of earnings growth. Under the model's strict assumptions, the growth rate equals the rate of capital appreciation (that is, the growth in the stock price).[20] In that

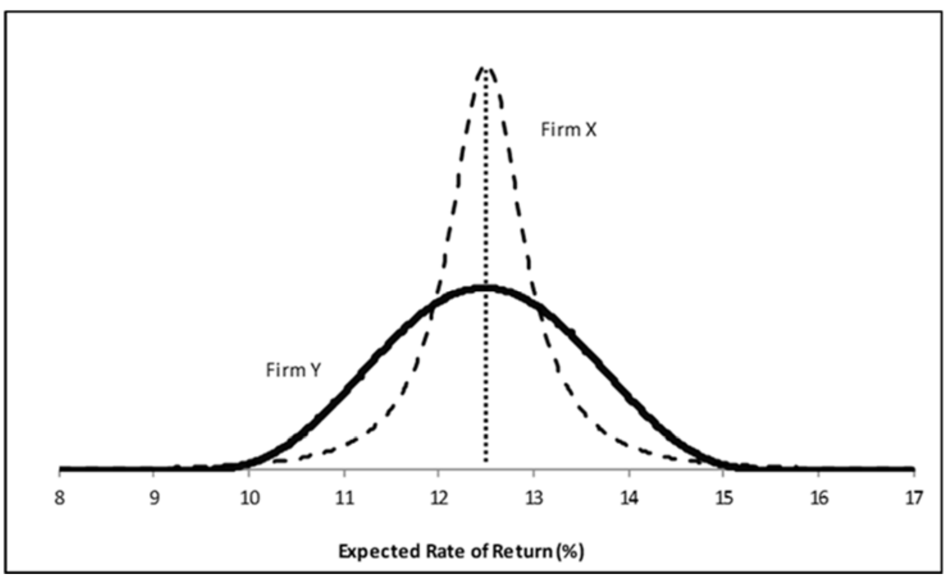
[20] As discussed in Appendix B, the model assumes that earnings, dividends, book value, and the stock price all grow at the same constant rate in perpetuity.

regard, it does not matter whether the investor holds the stock in perpetuity, or for a finite period during which the investor collects (and reinvests) dividends, then sells at the prevailing market price. Under the model's assumptions, the result is the same either way.

Q. 24 Please briefly describe the Capital Asset Pricing Model.

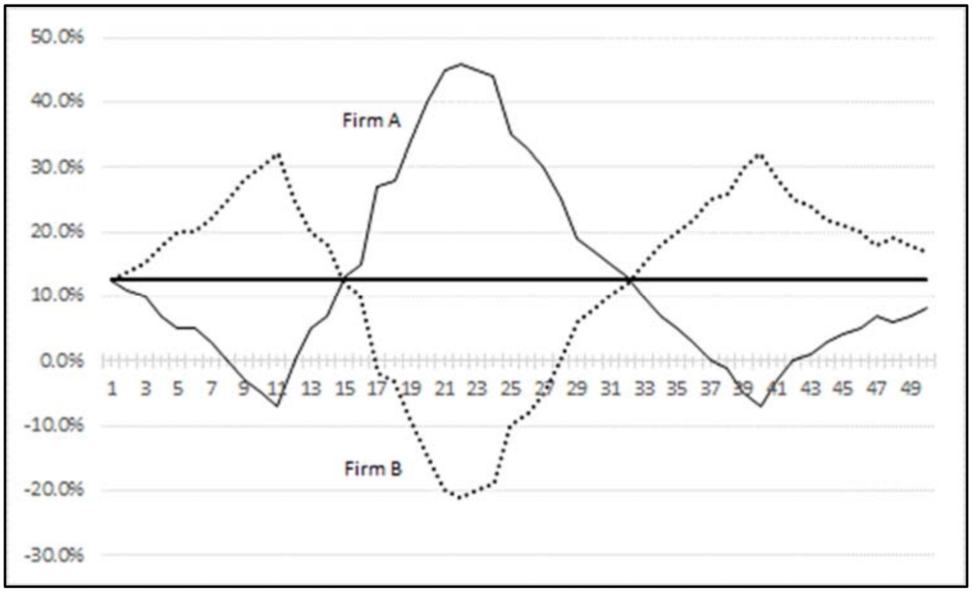
A. 24 Whereas DCF models focus on expected cash flows, Risk Premium-based models such as the CAPM focus on the additional return that investors require for taking on additional risk. In finance, "risk" generally refers to the variation in expected returns, rather than the expected return, itself. Consider two firms, X and Y, with expected returns, and the expected variation in returns noted in Chart 1, below. Although the two have the same expected return (12.50 percent), Firm Y's are far more variable. From that perspective, Firm Y would be considered the riskier investment.

Chart 1: Expected Return and Risk



Now consider two other firms, Firm A and Firm B. Both have expected returns of 12.50 percent, and both are equally risky as measured by their volatility. But as Firm A's returns go up, Firm B's returns go down. That is, the returns are negatively correlated.

Chart 2: Relative Risk



If we were to combine Firms A and B into a portfolio, we would expect a 12.50 percent return with no uncertainty because of the opposing symmetry of their risk profiles. That is, we can diversify away the risk. As long as two stocks are not perfectly correlated, we can achieve diversification benefits by combining them into a portfolio. That is the essence of the Capital Asset Pricing Model - because we can combine firms into a portfolio, the only risk that matters is the risk that remains after diversification, *i.e.*, the "non-diversifiable" risk.

The CAPM defines the Cost of Equity as the sum of the "risk-free" rate, and a premium to reflect the additional risk associated with equity investments. The "risk-free" rate is the yield on a security viewed as having no default risk, such as long-term Treasury bonds, and essentially sets the baseline of the CAPM. That is, an investor would expect a higher return than the risk-free rate to purchase an asset that carries risk. The difference between that higher return (*i.e.*, the required return) and the risk-free rate is the risk premium.

$$\text{Risk} - \text{Free Rate} + \text{Risk Premium} = \text{Required Return} \quad [1]$$

The Risk Premium is defined as a security's Beta coefficient multiplied by the risk premium of the overall market (the "Market Risk Premium" or "MRP"). The Beta coefficient is a measure of the subject company's risk relative to the overall market, *i.e.*, the "non-diversifiable" risk. A Beta coefficient of 1.00 means that the security is equally as risky as the overall market; a value below 1.00 represents a security with less risk than the overall market, and a value over 1.00 represents a security with more risk than the overall market. Equation [2] provides the general format of the CAPM formula:

$$\text{Risk} - \text{Free Rate} + (\text{Beta Coefficient x Market Risk Premium}) = \text{Required Return} \quad [2]$$

Q. 25 Please briefly describe the Bond Yield Plus Risk Premium approach.

A. 25 This approach is based on the basic financial principle that equity investors bear the risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders are riskier than returns to bondholders, equity investors must be compensated for bearing that additional risk (that difference often is referred to as the "Equity Risk Premium"). Bond Yield Plus Risk Premium approaches estimate the Cost of Equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds.

$$\text{Bond Yield} + \text{Equity Risk Premium} = \text{Required Return} \quad [3]$$

Q. 26 Please briefly describe the Expected Earnings approach.

A. 26 The Expected Earnings analysis is based on the principle of opportunity costs. Because investors may invest in, and earn returns on alternative investments of similar risk, those rates of return can provide a useful benchmark in determining the appropriate rate of return for a firm. Further, because those results are based solely on the returns expected by investors, exclusive of market-data or models, the Expected Earnings approach provides a direct comparison.

Q. 27 What are the results of your Constant Growth DCF?

A. 27 The results of the model described in Appendix B, part A are provided in Table 2, below.[21]

Table 2: Summary of DCF Results[22]

	Median	Median High
30-Day Average	9.61%	12.33%
90-Day Average	9.68%	12.38%
180-Day Average	9.71%	12.42%

Q. 28 Please now summarize your remaining analytical results.

A. 28 The Risk Premium-based results, including the CAPM, Bond Yield Plus Risk Premium and Expected Earnings methods, explained in detail in Appendix B, parts B, C and D, respectively, are provided below.

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[21] *See,* Appendix B for a more detailed description of the models, assumptions, and inputs described in this Section VI.

[22] For the purposes of my Direct Testimony, I have put more emphasis on the median results of my Constant Growth DCF analysis, because the mean results are affected by an anomalously high growth rate for Northwest Natural Gas Company of 25.50 percent from Value Line due to the company's significant losses in 2017.

Table 3: Summary of CAPM Results

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.03%)	9.12%	10.90%
Near Term Projected 30-Year Treasury (3.25%)	9.34%	11.12%
Long Term Projected 30-Year Treasury (4.05%)	10.14%	11.92%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.03%)	10.31%	12.44%
Near Term Projected 30-Year Treasury (3.25%)	10.52%	12.66%
Long Term Projected 30-Year Treasury (4.05%)	11.32%	13.46%

Table 4: Bond Yield Plus Risk Premium Results

Treasury Yield	***Return on Equity***
Current 30-Year Treasury (3.03%)	9.89%
Near Term Projected 30-Year Treasury (3.25%)	9.91%
Long Term Projected 30-Year Treasury (4.05%)	10.11%

Table 5: Expected Earnings Results

	Return on Equity
Low	10.05%
Median	10.57%
High	12.13%

VII. OTHER CONSIDERATIONS

Q. 29 What additional information did you consider in assessing the analytical results noted above?

A. 29 Because the methods discussed above provide a range of estimates, there are several additional factors that should be taken into consideration when establishing a reasonable range for the Company's Cost of Equity. Those factors include the risks associated with the Company's capital spending plan and regulatory recovery mechanisms and flotation costs associated with equity issuances.

Capital Spending and Regulatory Mechanisms

Q. 30 Have you reviewed the Company's regulatory recovery mechanisms?

A. 30 Yes. An important piece of my analysis includes an assessment of the Company's ability to earn its requested ROE. Accordingly, I have reviewed the Company's most recent financial statements, tariff and capital spending plans. The Company's regulatory environment should provide an opportunity to recover its costs and earn a reasonable return on its investments. Southwest Gas employs a decoupling mechanism to decouple operating margin from usage, and to offset weather volatility. In addition, the Company currently has two infrastructure replacement programs in place – the Customer-Owned Yard Line ("COYL"), and the Vintage Steel Pipe Replacement ("VSP"). In 2018, the Company invested a total of $128.60 million, including $26.60 million and $102.00 million in the COYL and VSP programs, respectively.[23] In this

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[23] *See,* Southwest Gas Holdings 2018 Year End Earnings Conference Call – Slide Presentation at http://investors.swgasholdings.com/phoenix.zhtml?c=117697&p=irol-calendarPast.

proceeding, the Company is requesting an additional infrastructure replacement mechanism for the accelerated replacement of M7000/8000 pipe.

Q. 31 Are decoupling and capital tracker mechanisms common among the proxy group companies?

A. 31 Yes, they are. Exhibit No._(RBH-8) provides a summary of the regulatory mechanisms and cost trackers currently in effect at each gas utility subsidiary of the proxy group companies. As Exhibit No._(RBH-8) demonstrates, substantially all of the proxy companies have both decoupling and capital recovery mechanisms in place.[24]

Under the *Hope* and *Bluefield* Comparable Earnings standard, the allowed Return on Equity should represent a return commensurate with the returns on investments of similar risk. To the extent the proxy companies have mechanisms in place to address revenue shortfalls or cost recovery, the Company's decoupling and infrastructure replacement mechanisms make it more comparable to its peers.

In addition, Exhibit No._(RBH-8) demonstrates that over a third, or eight of the 23 proxy group operating companies, employ more progressive alternative ratemaking plans, including formula-based rates. These plans often contain performance criteria covering a broad range of targets, while allowing the utility to recover prudent capital additions to its infrastructure.

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[24] Only four of the 23 proxy group operating companies do not have a decoupling mechanism. Similarly, only four of the 23 proxy group operating companies do not have a capital recovery mechanism.

Q. 32 Have you considered the Company's regulatory mechanisms in your determination of the Company's Cost of Equity?

A. 32 Yes. For the purpose of estimating the Cost of Equity, the principal analytical issue is whether the Company is so less risky than its peers as a direct result of the rate mechanisms that investors would specifically and measurably reduce their return requirement.[25] The fact that the Company's revenues may be affected by its regulatory mechanisms does not bear on the estimated Cost of Equity unless it can be demonstrated that the Company is materially less risky than the proxy group by virtue of the Company's regulatory mechanisms.

Moreover, the position that a reduction in volatility (whether of revenues, income, or cash flow) necessarily requires a reduction in the Cost of Equity runs counter to Modern Portfolio Theory, which is the fundamental basis of the CAPM. Under Modern Portfolio Theory, risk is defined as the uncertainty, or variability, of returns. Modern Portfolio Theory was advanced by recognizing that total risk may be separated into two distinct components: non-diversifiable risk, which is that portion of risk that can be attributed to the market as a whole; and non-systematic (or diversifiable) risk, which is attributable to the idiosyncratic nature of the subject company, itself. As noted in Appendix B, non-diversifiable risk is measured by the Beta coefficient within the CAPM structure.

Under Modern Portfolio Theory (and the CAPM), an investor would not be indifferent to a reduction in expected ROE in return for a reduction in volatility of revenues, unless the reduction in volatility specifically relates to reduced non-diversifiable risk. That is, any reduction in the Cost of Equity depends critically

[25] *See,* generally *Bluefield* and *Hope*.

on the type of risk that is reduced; if the risk assumed to be mitigated by the Company's regulatory mechanisms is diversifiable, there would be no reduction in the Cost of Equity even if total risk (diversifiable plus non-diversifiable risk) has been reduced. If, however, the regulatory mechanisms mitigate increased systematic risk associated with the factors that drove the Commission to approve the mechanisms in the first place, there likewise would be no effect on the Cost of Equity.

Q. 33 Please explain how the variability of profit relates to decoupling mechanisms and measures of risk.

A. 33 The argument that decoupling mechanisms reduce risk stems from the position that decoupling mechanisms reduce revenue volatility. Because revenue can come from various rate structures (i.e., customer charges, volumetric rates, cost recovery mechanisms, decoupling mechanisms, etc.), it is difficult to discern from publicly available data the extent to which decoupling structures affect changes in revenue. Even if it were the case that revenue decoupling mechanisms mitigate some measure of "risk," they only would affect the Company's Cost of Equity if: (1) the effect of the mechanism was to reduce the Company's risk below that of its peers; and (2) investors knowingly reduced their return requirements as a direct consequence of the mechanisms. Because rating agencies and investors tend to focus on measures of profit and cash flow, relevant considerations are whether cash flow variability differs across companies and what those differences, if any, may imply for the Cost of Equity.

Q. 34 Have you performed any analysis of the Company's profit variability relative to the proxy group?

A. 34 Yes. In its discussion of profitability, and how profitability weighs in its assessment of financial risk, Standard & Poor's ("S&P") explains that it bases "the volatility of profitability on the standard error of the regression ("SER") for a company's historical EBITDA (Earnings Before Interest, Taxes, Depreciation, and Amortization), EBITDA margins, or return on capital." Under that approach S&P divides the SER by the average (SER/Average), "to ensure better comparability across companies."[26] S&P further notes:

> The SER is a statistical measure that is an estimate of the deviation around a 'best fit' linear trend line. We regress the company's EBITDA, EBITDA margins, or return on capital against time. A key advantage of SER over standard deviation or coefficient of variation is that it doesn't view upwardly trending data as inherently more volatile.[27]

Consistent with S&P's approach, I plotted the proxy group's[28] and the Company's annual EBITDA from 2005 to 2017 and graphed the "best fit" linear trend line. As shown in Chart 3 below, the deviations around the best-fit trend line are similar for the two. Time explains about 88.00 percent of the change in the proxy group's average EBITDA and about 95.00 percent of the change in the Company's EBITDA.

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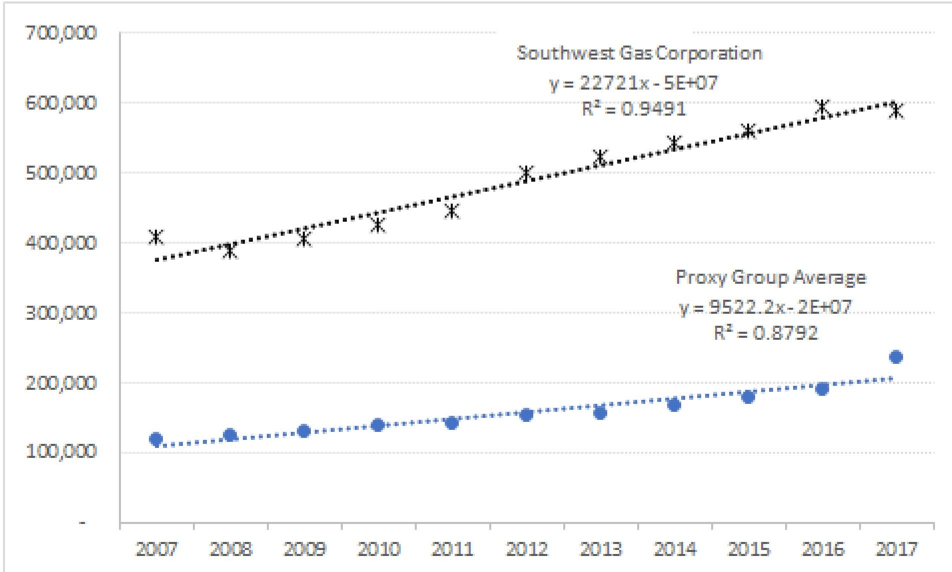
[26] Standard & Poor's RatingsDirect, *Corporate Methodology*, November 19, 2013, at 27.
[27] *Ibid.*
[28] Proxy group average at the operating company level.

Chart 3: Annual EBITDA 2007 – 2017[29]



The Company's ratio of the SER/Average EBITDA (0.04) is somewhat lower (that is, less variable) than the proxy group average (0.08). On balance, there is little variability between the two, and the data suggests the Company's risk profile is similar to its peers.

Q. 35 Does the financial community recognize the benefit of revenue stabilization mechanisms?

A. 35 Yes. Value Line, for example, has noted a number of mechanisms that are currently employed by utilities to reduce regulatory lag. In its review, Value Line specifically notes recovery mechanisms for capital expenditures, tracking mechanisms for certain kinds of expenses, and decoupling mechanisms as methods to reduce regulatory lag and provide utilities the opportunity to earn their authorized returns.[30] In fact, Value Line believes that the use of such

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[29] Source: SNL Financial.

[30] *See,* Paul E. Debbas, CFA, *What Electric Utilities Are Doing about Regulatory Lag*, Value Line, May 23, 2012.

mechanisms "is likely to increase as utilities request similar mechanisms in additional states."[31] Similarly, S&P noted that it has "seen many state commissions approve alternative ratemaking techniques to traditional base rate case applications, which help utilities sustain cash flow measures, earnings power, and ultimately, credit quality."[32]

Q. 36 Are you aware of any studies that have addressed the relationship between decoupling mechanisms generally, and the cost of capital?

A. 36 Yes. In March 2014, The Brattle Group ("Brattle") published a study addressing the effect of revenue decoupling structures on the cost of capital for electric utilities.[33] In its report, which extended a prior analysis focused on natural gas distribution utilities, Brattle pointed out that although decoupling structures may affect revenue, net income still can vary.[34] Brattle further noted that the distinction between diversifiable and non-diversifiable risk is important to equity investors and, as such, the relationship between decoupling and the Cost of Equity should be examined in that context. Further to that point, Brattle noted that while reductions in total risk may be important to bondholders, only reductions in non-diversifiable business risk would justify a reduction to the ROE.[35]

Brattle's empirical analysis examined the relationship between decoupling and the After-Tax Weighted Average Cost of Capital ("ATWACC") for a group of electric utilities that had implemented decoupling structures in various

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[31] Paul E. Debbas, CFA, *What Electric Utilities Are Doing about Regulatory Lag*, Value Line, May 23, 2012.

[32] S&P RatingsDirect, *Industry Economic and Ratings Outlook: U.S. Regulated Utilities Expected To Continue On Stable Trajectory In 2013*, dated January 25, 2013.

[33] *See,* The Brattle Group, *The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation*, Prepared for the Energy Foundation, March 20, 2014.

[34] *Ibid,* at 7.

[35] *Ibid,* at 8.

jurisdictions throughout the United States. As with Brattle's 2014 study, the updated study found that there was no statistically significant link between the cost of capital and revenue decoupling structures.[36] In February 2019 Brattle reaffirmed its findings, stating for both electric and natural gas utilities "[s]tatistical analyses does not show an impact on [cost of capital] from decoupling."[37]

Q. 37 Are you aware of other research regarding the relationship between decoupling and the Cost of Equity?

A. 37 Yes. My colleagues at ScottMadden (Pauline Ahern, and Dylan D'Ascendis), together with Dr. Richard Michelfelder of the Rutgers School of Business, examined the relationship between decoupling and the Cost of Equity among electric, gas, and water utilities. Using the generalized consumption asset pricing model, the authors found decoupling to have no statistically significant effect on investor perceived risk and the Cost of Equity.[38]

Q. 38 What do you conclude from those studies?

A. 38 Although they apply different methods, the studies arrive at a consistent conclusion: There is no empirical relationship between decoupling and the Cost of Equity.

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[36] *See,* The Brattle Group whitepaper (updated study), *Effect on the Cost of Capital of Innovative Ratemaking that Relaxes the Linkage between Revenue and kWh Sales – An Updated Empirical Investigation,* by Michael J. Vilbert, Joseph B. Wharton, Shirley Zhang and James Hall, November 2016. Also available at http://files.brattle.com/files/5711_effect_on_the_cost_of_capital_of_ratemaking_that_relaxes_the_linkage_between_revenue_and_kwh_sales.pdf.

[37] The Brattle Group, *Decoupling and its Impact on Cost of Capital Presented to SURFA Members and Friends*, dated February 27, 2019 [clarification added].

[38] *See,* Dr. Richard Michelfelder, Pauline Ahern, Dylan D'Ascendis, *Revenue-Sales Decoupling Impact on Public Utility Conservation Investment*, currently submitted and under review – Energy Policy Journal, dated January 2019.

Q. 39 Have you also reviewed past decisions to determine whether regulatory commissions are inclined to adjust the authorized ROE in connection with decoupling mechanisms?

A. 39 Yes. I am aware of two regulatory commissions (the Maryland Public Service Commission, and the Public Service Commission of the District of Columbia) that historically had made adjustments for decoupling mechanisms, but no longer do so.[39] Similarly, in the Company's 2018 Nevada rate case, the Public Utilities Commission of Nevada found that "…an adjustment for SWG's revenue decoupling mechanism is unnecessary" and continued to explain that "[a]ll of the companies in the Proxy Group have some form of a rate stabilization mechanism in place; thus, the lower risk associated with revenue decoupling is accounted for in the results of the ROE study."[40] In fact, I am unaware of any regulatory commission that currently applies an adjustment to ROE due to the use of a decoupling mechanism in natural gas rate cases.

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[39] *See,* Public Service Commission of the District of Columbia, Formal Case No. 1139, Order No. 18846, dated July 25, 2017, at ¶ 294.

[40] Public Utilities Commission of Nevada, Docket 12-04005, Second Modified Final Order, at ¶ 149.

Q. 40 Do the Company's infrastructure replacement programs recover all its capital spending?

A. 40 No, they do not. In 2018, the COYL and VSP mechanisms recovered only 31.28 percent of the Company's total capital spending in Arizona.[41] Looking forward, the Company expects to recover $412.24 million under its COYL and VSP mechanisms, or 40.65 percent of its three-year 2019-2021 $1,014.20 million capital spending forecast in Arizona.[42] As the Company moves forward with its capital spending plan, internally generated cash and retained earnings will be an important source of funding, mitigating the delay of cost recovery.

Q. 41 Please further discuss the Company's need to rely on internally generated cash flow and retained earnings to fund capital investments.

A. 41 It is particularly important for utilities to fund capital investments with internally generated cash flow which is driven by cost recovery "of", and return "on" its investments. Since 2017, when the Company completed its last rate case, its ratio of cash flow from operating activities to capital expenditures has remained considerably below its peers (see Chart 4, below).[43] Because its cash flows have been less able to support its capital investment, the Company must access external capital, increasing the potential for negative credit consequences.

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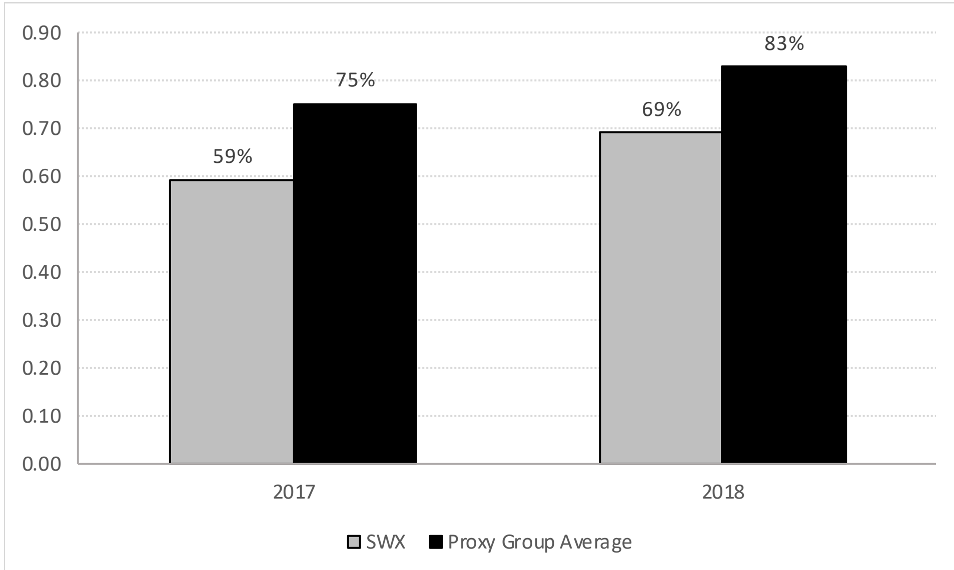
41 Company-provided. Arizona total capital expenditures were $411.07 million in 2018.

42 Company-provided.

43 Southwest Gas's two-year average of CFFO-to-Capital Expenditures was 64.19 percent compared to the proxy group two-year average of 79.03 percent.

Chart 4: Historical Cash Flow From Operating Activities to Capital Expenditures[44]



Retained earnings is an important funding mechanism because net income is a primary source of operating cash flow, which reduces the Company's need to rely on external capital. As shown above, however, the Company's capital expenditures have considerably exceeded its operating cash flow, even more so than its peers.

[44] Source: SNL Financial. Reflects proxy group consolidated financial results publicly available through U.S. Securities and Exchange Commission filings. Operating company-level regulated financial results are not consistently available through various state agencies, but I believe that the consolidated financial results reflect a good comparison because of the high percentage of regulated operations prevalent for the proxy group. For the proxy group, regulated gas operating income reflects 81.58 percent (calculated excluding NWN and SJI because of large losses in 2017) of total operating income on average.

Q. 42 Have you evaluated how the Company's ratings compare to that of the proxy group?

A. 42 Yes, in Exhibit No._(RBH-11) I evaluated the Company's ratings relative to the proxy group. The proxy group average Moody's and S&P ratings are A2 and A-, respectively. Both agencies rate the Company one "notch" lower, at A3 and BBB+, respectively.

I also have reviewed rating agencies views of the Company's regulatory framework[45] relative to the proxy group (see Exhibit No._(RBH-12)). As that Exhibit indicates, the Company ranks below the proxy group average in three of Moody's four regulatory criteria: (1) Consistency and Predictability of Regulation; (2) Timeliness of Recovery of Operating and Capital Costs; and (3) Sufficiency of Rates and Return. Those results suggest higher risk and, therefore, higher costs of capital.

Q. 43 What are your conclusions regarding the effect of the Company's decoupling mechanism and capital investment plan and its associated regulatory mechanisms?

A. 43 As noted above, decoupling mechanisms have become increasingly common for companies facing the inability to recover prudently incurred fixed costs. In that regard, the proxy companies have implemented many forms of rate stabilization mechanisms that provide for cost recovery similar to that provided by a revenue-decoupled rate design. Consequently, investors increasingly expect some form of stabilization will be implemented in utility rate regulation.

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[45] Moody's assigns 50.00 percent of its rating assessment based on the nature of regulation. *See*, Moody's Investors Service, *Regulated Electric and Gas Utilities*, June 23, 2017, at 4.

Moreover, there is no evidence of which I am aware indicating companies that have implemented such structures either have lower required ROEs or have significantly different market valuations. In fact, the Brattle study; the Michelfelder, Ahern, and D'Ascendis paper; and recent decisions by the Maryland and District of Columbia regulatory commissions support that conclusion.

The Company's capital expenditure plan is significantly larger than its internally generated cash placing downward pressure on its free cash flow, and likely its credit profile. The Company's capital recovery mechanisms provide for more timely recovery of investments, enhancing the ability to fund investments with internally generated cash and mitigating financing risk. Although the Company's infrastructure replacement programs may be credit-supportive, they are not necessarily credit-enhancing. Consequently, the Commission's decision regarding the Company's ROE in this proceeding will directly affect the Company's ability to fund capital investments with operating cash flows, and the financial community's view of its financial profile.

I therefore conclude that a revenue-decoupled rate design, in addition to the Company's infrastructure recovery mechanisms, should have no downward effect on my ROE estimate.

Flotation Costs

Q. 44 What are flotation costs?

A. 44 Flotation costs are the costs associated with the sale of new issues of common stock. These include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance.

Q. 45 Are flotation costs part of the utility's invested costs or part of the utility's expenses?

A. 45 Flotation costs are part of capital costs, which are properly reflected on the balance sheet under "paid in capital" rather than current expenses on the income statement. Flotation costs are incurred over time, just as investments in rate base or debt issuance costs. As a result, the great majority of flotation costs are incurred prior to the test year but remain part of the cost structure during the test year and beyond.

Q. 46 Is the need to consider flotation costs eliminated because Southwest Gas is a wholly owned subsidiary?

A. 46 No. Like the Company's Arizona operations, wholly owned subsidiaries receive equity from their parent, who compete with other issuers in capital markets. The ability to efficiently raise capital depends on the subsidiaries' ability to earn reasonable returns on the equity invested by the parent. To deny the recovery of the issuance costs required to raise that capital ultimately would penalize the investors that fund the utility operations and would inhibit the company's ability to efficiently raise new equity capital. This is important for companies such as Southwest Gas that are planning continued investments in the near term, and for which access to capital (at reasonable cost rates) to fund those investments will be crucial.

Q. 47 How did you calculate the flotation cost recovery adjustment?

A. 47 I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. My estimate of flotation costs recognizes the costs of issuing equity that were incurred by the proxy companies in their most recent two issuances. As shown in Exhibit No._(RBH-9), an adjustment of 0.07 percent (*i.e.*, 7 basis points) reasonably represents flotation costs for the Company.

Q. 48 Is the need to consider flotation costs recognized by the academic and financial communities?

A. 48 Yes. The need to reimburse investors for equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. For example, Dr. Morin notes that "[t]he costs of issuing [common stock] are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit the recovery of these costs."[46] Dr. Morin further notes that "equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely."[47] This treatment is consistent with the philosophy of a fair rate of return. As explained by Dr. Shannon Pratt:

> Flotation costs occur when a company issues new stock. The business usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the business. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the business's required returns must be greater to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the net cash flow to discount, or by incorporating the cost into the cost of equity capital. Since flotation costs typically are not applied to operating cash flow, they must be incorporated into the cost of equity capital.[48]

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[46] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 321.
[47] *Id.*, at 327.
[48] Shannon P. Pratt & Roger J. Grabowski, *Cost of Capital: Applications and Examples* at 586 (4th ed. 2010).

Morningstar also has commented on the need to reflect flotation costs in the cost of capital:

> Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital).[49]

Q. 49 Have regulatory commissions in other jurisdictions recognized flotation costs when determining the authorized ROE?

A. 49 Yes. FERC, along with regulatory commissions in jurisdictions such as Arkansas, Connecticut, and Mississippi have recognized flotation costs when determining the authorized ROE.[50] Although the method by which flotation costs are reflected in rates may vary (*e.g.*, implicit versus explicit basis point increases to authorized ROE), the recognition of those costs is not limited to, or constrained by recent equity issuances. For instance, the Arkansas Commission stated that "including some level of valid, sustainable, measurable, and material flotation costs in equity return is appropriate."[51]

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[49] Morningstar, Inc. Ibbotson SBBI 2013 Valuation Yearbook, at 25.

[50] *See*, *for example*, FERC Docket Nos. EL05-19-002 and ER05-168-001, *Golden Spread Electric Cooperative, Inc., v. Southwestern Public Service Company,* Opinion No. 501, 123 FERC ¶ 61,0047, (April 21, 2008); Arkansas Public Service Commission, Docket No. 04-176-U, *In the Matter of the Application of Arkansas Western Gas Company for Approval of a General Change in Rates and Tariffs*, Order No. 6, October 31, 2005, at 34; Connecticut Public Utilities Regulatory Authority, Docket No. 14-05-06, *Application of the Connecticut Light and Power Company to Amend Rate Schedules*, Decision, December 17, 2014, at 133-134, 145 (Table 64), and 223 (PP 280-281); Mississippi Public Service Commission, Docket No. 01-UN-0548, *Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi*, Final Order, December 3, 2001, at 26.

[51] *Id*.

Q. 50 Are you proposing to adjust your recommended ROE by seven basis points to reflect the effect of flotation costs on the Company's ROE?

A. 50 No. Rather, I have considered the effect of flotation costs, in addition to the Company's regulatory recovery of its capital spending plan relative to the proxy group, in determining where the Company's ROE falls within the range of results.

VIII. CAPITAL MARKET ENVIRONMENT

Q. 51 Do economic conditions influence the required cost of capital and required return on common equity?

A. 51 Yes. As discussed in Section VI and in Appendix B, the models used to estimate the Cost of Equity are meant to reflect, and therefore are influenced by, current and expected capital market conditions. It therefore is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent certain ROE estimates are incompatible with such data, or inconsistent with basic financial principles, it would be appropriate to consider whether alternative estimation techniques are likely to provide more meaningful and reliable results.

Q. 52 Do you have any general observations regarding the relationship between federal reserve monetary policy, capital market conditions, and the Company's Cost of Equity?

A. 52 Yes. Although the Federal Reserve completed its Quantitative Easing initiative in October 2014, it was not until December 2015 that it raised the Federal Funds rate and began the process of monetary policy normalization.[52] A significant analytical issue is how investors likely will react as that process continues, and

[52] *See,* Federal Reserve Press Release, December 16, 2015.

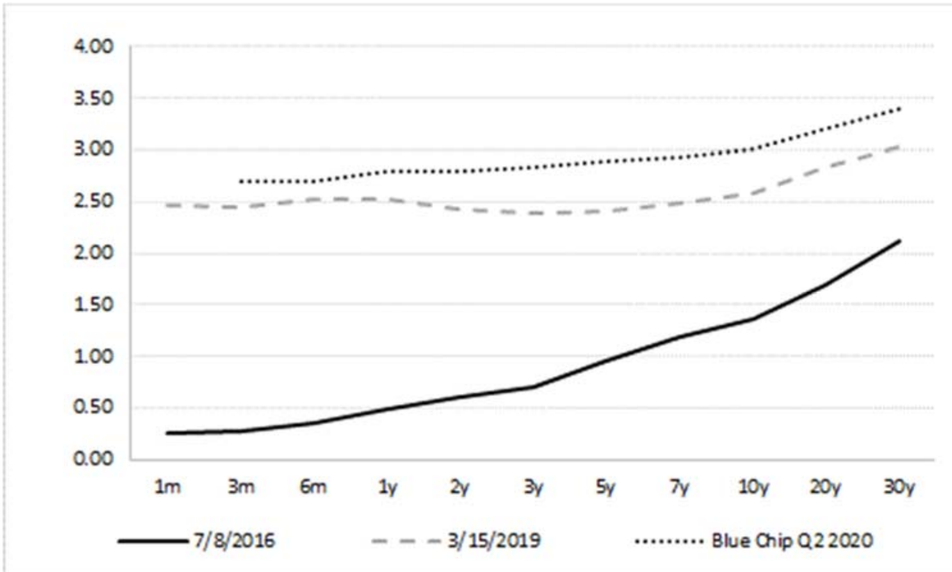
eventually is completed. For example, increasing interest rates may be seen as an indication of expanding macroeconomic growth, in which case we reasonably could expect the growth rate component of the Discounted Cash Flow model to increase. At the same time, sectors that historically have included dividend-paying companies lost value, as increasing interest rates provide investors with alternative sources of current income. A more reasoned approach is to understand the relationships among capital market and macroeconomic variables, and to consider how those factors may affect different models and their results.

Q. 53 Does your recommendation consider the interest rate environment?

A. 53 Yes. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. Although all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst, and the capital market environment in which the analyses were undertaken. Because the Cost of Equity is forward-looking, the salient issue is whether investors see the likelihood of increasing costs of capital during the period in which the rates set in this proceeding will be in effect.

Although the Federal Reserve's market intervention policies kept interest rates historically low, since July 8, 2016 (when the 30-year Treasury yield fell to its secular low of 2.11 percent) rates have risen. As the Federal Reserve increased the Federal Funds target rate eight times between December 2016 and December 19, 2018 to 2.25 percent - 2.50 percent, short-term and long-term interest rates also increased (*see* Chart 5 below).[53]

Chart 5: Treasury Yield Curve: 7/8/2016, 3/15/2019 and Projected Q2 2020[54]



In a press conference following the December 2018 Federal Open Market Committee meeting, Chairman Powell discussed the recent increases in the Federal Funds rate and the expectation for some further gradual rate increases, noting a strengthening economy, a strong labor market and rising wages.[55]

Aside from increases in the Federal Funds rate, in October 2017, the Federal Reserve initiated its balance sheet normalization program that includes gradual reductions to its security holdings by decreasing its reinvestment

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[53] Federal Reserve Board Schedule H.15. One-year, 10-year and 30-year Treasury yields increased by 204 basis points, 122 basis points and 91 basis points, respectively, July 8, 2016 to March 15, 2019.
[54] Federal Reserve Board Schedule H.15; Blue Chip Financial Forecasts, Vol. 38, No. 3, March 1, 2019, at 2. Three-year, seven-year and 20-year projected Treasury yields interpolated.
[55] *See,* Transcript of Chairman Powell's Press Conference, December 19, 2018.

activities.[56] In the January 2019 meeting, the Federal Reserve decided to continue with the balance sheet wind-down.[57] At the same time, the supply of marketable U.S. Treasury securities has increased by approximately $1.14 trillion.[58] The growing supply of Treasury securities from both the Federal Reserve and the U.S. Treasury puts upward pressure on Treasury rates.

Q. 54 Does market-based data indicate that investors see a probability of increasing interest rates?

A. 54 Yes. Consensus near-term forecasts of the 30-year Treasury yield reported by Blue Chip Financial Forecast indicate the market expects long-term rates to reach 3.40 percent by the second quarter of 2020.[59] Importantly, the potential for rising rates represents risk for utility investors.

Q. 55 Has market volatility changed with the federal reserve's move toward monetary policy normalization?

A. 55 Yes. A visible and widely reported measure of expected volatility is the Chicago Board Options Exchange ("Cboe") Volatility Index, often referred to as the VIX. As Cboe explains, the VIX "is a calculation designed to produce a measure of constant, 30-day expected volatility of the U.S. stock market, derived from real-

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[56] *See,* https://www.federalreserve.gov/monetarypolicy/policy-normalization.htm and Federal Open Market Committee ("FOMC") Press Release, June 14, 2017. In its January 30, 2019 press release the FOMC noted that although it continues to view changes in the federal funds target rate as the "primary means of adjusting monetary policy", it also would adjust the details of its balance sheet normalization based on economic and financial developments. *See*, Federal Reserve Press Release dated January 30, 2019. At its March 2019 meeting, the FOMC determined it would hold the Federal Funds target rate constant, looking to current and expected economic conditions to determine future rate adjustments. *See*, Federal Reserve Press Release dated March 20, 2019.

[57] Federal Reserve Press Release dated January 30, 2019.

[58] Source: United States Treasury, Monthly Statement of the Public Debt. *See,* https://www.treasurydirect.gov/govt/reports/pd/mspd/mspd.htm. U.S. marketable securities increased from $14.48 trillion to $15.62 trillion between December 31, 2017 and December 31, 2018.

[59] Blue Chip Financial Forecast*,* Vol. 38, No. 3, March 1, 2019, at 2.

time, mid-quote prices of S&P 500® Index call and put options."[60] Simply, the VIX is a market-based measure of expected volatility. Because volatility is a measure of risk, increases in the VIX, or in its volatility, are a broad indicator of expected increases in market risk.

Although the VIX is not expressed as a percentage, it should be understood as such. That is, if the VIX stood at 15.00, it would be interpreted as an expected standard deviation in annual market returns of 15.00 percent over the coming 30 days. Since 2000, the VIX has averaged about 19.67, which is highly consistent with the long-term standard deviation on annual market returns (19.80 percent, as reported by Duff & Phelps).[61]

As Chart 6 (below) demonstrates, in 2017 market volatility was well below its long-term average and moved within a somewhat narrow range; the VIX averaged about 11.09, with a standard deviation of 1.36. Between January 2018 and March 2019, the VIX average increased to 16.68 with a standard deviation of 4.77. That is, since 2017, both the level and the volatility of market volatility increased.

[60] Source: http://www.cboe.com/vix.
[61] Source: Duff & Phelps, 2019 SBBI Yearbook, at 6-17.

Chart 6: VIX Since January 2017[62]

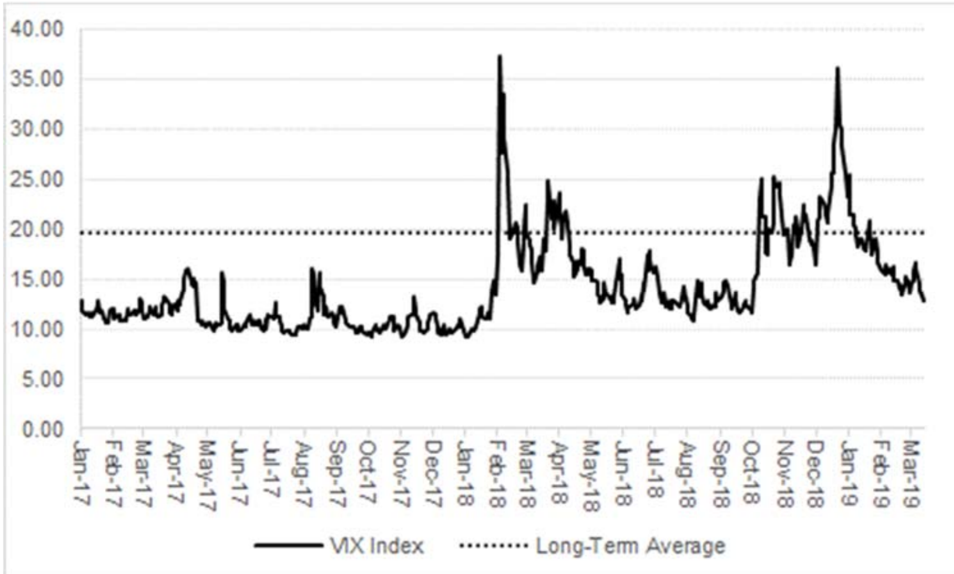

Table 6 (below) further demonstrates the increase in market uncertainty from 2017 to 2019. As that table notes, the standard deviation (that is, the volatility of volatility) in 2018-2019 is about 3.50 times higher than its 2017 level (1.356).

Table 6: VIX Levels and Volatility[63]

Long-Term Average	19.674
2018-2019 Average	16.676
2018-2019 Maximum	37.320
2018-2019 Minimum	9.150
2018-2019 Standard Deviation	4.772
2017 Average	11.090
2017 Maximum	16.040
2017 Minimum	9.140
2017 Standard Deviation	1.356

[62] Source: Bloomberg Professional. Data through March 15, 2019.
[63] Source: Bloomberg Professional. Data through March 15, 2019.

The increase in volatility is not surprising as market participants reassess investment alternatives in light of the Federal Reserve's shift toward monetary policy and the passage of new tax legislation.

Q. 56 Is market volatility expected to increase from its current levels?

A. 56 Yes, it is. One means of assessing market expectations regarding the future level of volatility is to review Cboe's "Term Structure of Volatility." As Cboe points out:

> The implied volatility term structure observed in SPX options markets is analogous to the term structure of interest rates observed in fixed income markets. Similar to the calculation of forward rates of interest, it is possible to observe the option market's expectation of future market volatility through use of the SPX implied volatility term structure.[64]

Cboe's term structure data is upward sloping, indicating market expectations of increasing volatility. The expected VIX value in June 2020 is about 17.76, suggesting investors see a reversion toward the long-term average volatility over the coming months.[65] That increase in expected volatility makes intuitive sense, given the Federal Reserve's movement toward normalizing monetary policy. That policy change includes reducing the liquidity provided to the financial markets during the Federal Reserve's Quantitative Easing initiatives. Because that liquidity had the effect of dampening volatility as it was added to the markets, it stands to reason that volatility will increase as liquidity is diminished.

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[64] Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.

[65] Source:http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data, data as of March 15, 2019.

Q. 57 Does the federal reserve's tightening of monetary policy have other implications for the assessment of capital markets?

A. 57 Yes. Just as the Federal Reserve's monetary policy in the post-financial crisis era was aimed at lowering interest rates and market volatility, its "normalization" will tend to increase both. Because it is at least a directional indicator of investors' return requirements, the elevated uncertainty supports my recommended range.

It also is important to recognize that the Federal Reserve's reduction in monetary stimulus is related to expectations of improved economic and financial conditions, and sustained growth in the overall economy. When increasing the Federal Funds rate on December 19, 2018, the Federal Open Market Committee noted the labor market continued to strengthen and that household spending was rising at a strong rate while business fixed investment had moderated from its rapid pace earlier in the year.[66] Although it did not increase the Federal Funds rate in its January 2019 meeting, the Federal Open Market Committee observed the labor market continued to strengthen, and economic activity continued to rise at a solid rate.[67] From that perspective, we would expect to see higher growth estimates for companies in the overall economy, including the utility sector.

Q. 58 What conclusions do you draw from your analyses of the current capital market environment, and how do those conclusions affect your ROE recommendation?

A. 58 From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE estimate, including assessments of capital market conditions, are consistent with the conclusion itself. Although all analyses require an element of judgment, the application of that judgment must be made in the

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[66] *See,* Federal Reserve Press Release dated December 19, 2018.
[67] *See,* Federal Reserve Press Release dated January 30, 2019.

context of the quantitative and qualitative information available to the analyst and the capital market environment in which the analyses were undertaken. Because the application of financial models and interpretation of their results often is the subject of differences among analysts in regulatory proceedings, it is important to review and consider a variety of data points. That approach enables us to put in context both quantitative analyses and the associated recommendations. Further, because all models produce ranges of results, it is important to consider the type of information discussed above to determine where the Company's ROE falls within those ranges. As discussed throughout my testimony, doing so supports my recommended range of 10.00 percent to 10.75 percent.

IX. FAIR VALUE RATE BASE

Q. 59 Please briefly summarize the Fair Value standard in Arizona.

A. 59 As noted in Chapparal,[68] the Arizona Constitution requires the use of a fair value rate base in establishing rates. Article 15 Para. 14 of the Arizona Constitution states:

> The corporation commission shall, to aid it- in the proper discharge of its duties, ascertain the fair value of the property within the state of every public service corporation doing business therein, and every public service corporation doing business within the state shall furnish to the commission all evidence in its possession, and all assistance in its power, requested by the commission in aid of the determination of the value of the property within the state of such public service corporation.

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[68] *See,* In the Matter of the Application of Chapparal City Water Company, an Arizona Corporation, for a Determination of the Current Fair Value of its Utility Plant and Property and for Increases in its Rates and Charges for Utility Service Based Thereon, Docket No. W-02113A-04-0_16, Arizona Corporation Commission Decision No. 70441, July 28, 2008, at 20-21.

Although I am not an attorney, I understand that, as interpreted by the Arizona Court of Appeals, this paragraph requires the Commission to find the fair value of a public service corporation's property, and to use that value to set just and reasonable rates.[69]

Q. 60 Are you aware of references in academic literature regarding the use of fair value to set rates?

A. 60 Yes. As Phillips states:

> There is a third measure of value, which depends upon the two discussed above: fair value. *Fair Value* is a figure somewhere between original cost and reproduction cost, arrived at by the exercise of "enlightened judgment" or by specific formula.
>
> ***
>
> With respect to the second question concerning the weighting problem, the commissions generally do not allow the full valuation estimate based upon reproduction cost or trended original cost. As a result, the final valuation figure chosen represents a compromise.[70]

Q. 61 How did the Company establish the Fair Value Rate Base?

A. 61 As discussed in the testimony of Witness Cunningham, the Company calculated the fair value rate base ("FVRB") as the simple average of the original cost rate base ("OCRB") and the reconstruction cost new less depreciation ("RCND") of the utility system, which is estimated to be $3,234,113,450.[71] The OCRB of $1,991,543,072 is based on the Company's plant accounting records, as of January 31, 2019, (see page 1 of Exhibit No._(RBH-10)). The resulting FVRB is $2,612,828,261.

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[69] *Ibid.*
[70] Phillips, Charles F., The Regulation of Public Utilities, Third Edition, Public Utilities Reports, Inc., pp. 319, 339 *(emphasis included)*.
[71] Prepared Direct Testimony of Randi L. Cunningham.

X. FAIR VALUE RATE OF RETURN

Q. 62 Does the Fair Value standard also require consideration of the fair return on the fair value of the Company's assets?

A. 62 Yes. As noted above, the Arizona Constitution requires that the Commission establish just and reasonable rates using the fair value of the Company's property. In establishing the revenue requirement, the Commission would also need to establish the appropriate ROE to apply to the equity component of the FVRB.

Q. 63 Have you calculated the fair value rate of return ("FVROR") on the FVRB?

A. 63 Yes. As shown on page 1 of Exhibit No._(RBH-10), I estimate that FVROR to be 5.98 percent.

Q. 64 Please explain how you calculated the FVROR.

A. 64 As shown in Exhibit No._(RBH-10), and in Table 7 (below), I calculated the difference between the OCRB and the Company's proposed FVRB. That difference represents the appreciation in the value of the assets based on the current market value of the OCRB, and has been commonly referred to as the "fair value increment."[72] I then weighted the OCRB using the Company's proposed capital structure, which includes the debt and equity component of the OCRB, and the appreciation in the value of the assets which, when added to the OCRB, results in the FVRB.

Q. 65 How did you apply the equity and debt costs to derive the FVROR?

A. 65 As shown in Table 7, I applied the Company's actual cost of debt to the debt component of the OCRB and my recommended ROE to the equity component of

[72] *See,* Arizona Corporation Commission, Decision No. 70665, at 32.

the OCRB consistent with the Commission's decision in Decision No. 70665.[73] I applied 50.00 percent of the risk free rate of return of 1.32 percent to the market appreciation of the FVRB.

Q. 66 How did you estimate the risk-free rate of return?

A. 66 My estimate of the nominal risk-free rate of return is the average of *Blue Chip Financial Forecast's* (1) short-term projected yield on 30-year Treasury bonds of 3.25 percent, and (2) long-term projected yield on the 30-year Treasury bonds of 4.05 percent.[74] I then adjusted the nominal risk free rate of 3.65 percent by the rate of inflation, which I estimated to be 2.30 percent. The resulting real risk-free rate is then 1.32 percent.[75]

Q. 67 How did you estimate the rate of inflation?

A. 67 I calculated the inflation rate of 2.30 percent based on the average of two measures of inflation: the *Blue Chip Financial Forecast* estimate of the long term change in the Consumer Price Index ("CPI") for 2025 through 2029, which is 2.20 percent, and the *EIA Annual Energy Outlook* estimate of the change in CPI for the period from 2018 through 2050, of 2.40 percent.

Q. 68 What is the resulting FVROR using that approach?

A. 68 As shown on page 1 of Exhibit No._(RBH-10), based on the calculation discussed previously, the FVROR that would be applied to the FVRB is 5.98 percent.

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[73] Arizona Corporation Commission Decision No. 70665, In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to its Operations Throughout the State of Arizona, December 24, 2008 at 31. In that decision, the Commission determined that the Staff's approach of applying one-half of the risk-free rate to the fair value increment was appropriate.

[74] For the short-term projected yield, *see, Blue Chip Financial Forecasts*, Vol. 38, No. 3, March 1, 2019, at 2, consensus projections of the 30-year Treasury yield for the six quarters ending June 2020; For the long-term projected yield, *see Blue Chip Financial Forecasts*, Vol. 37, No. 12, December 1, 2018, at 14, consensus projections of the 30-year Treasury yield for the periods 2020-2024 and 2025-2029..

[75] 0.0132 = [(1.0365/1.0230)-1]

Table 7: Calculation of the Fair Value Rate of Return[76]

CAPITAL	AMOUNT	PERCENT	COST RATE	WEIGHTED COST RATE
Long-Term Debt	$ 973,864,562	37.27%	4.86%	1.81%
Common Equity	1,017,678,510	38.95%	10.30%	4.01%
Total Capital OCRB	$ 1,991,543,072			
Appreciation Above OCRB	621,285,189	23.78%	0.66%	0.16%
Total Capital FVRB	$ 2,612,828,261	100.00%		5.98%

Q. 69 Do you believe the FVROR is a reasonable estimate of the Company's Cost of Capital?

A. 69 The FVROR of 5.98 percent provided in Table 7 (above) is a conservative estimate of the appropriate cost of capital for rate base included in the Company's general rate case. Applying 50.00 percent weight to the OCRB, which is a measure of book value, and 50.00 percent to the RCND, a measure of market value, produces a conservative estimate of FVRB, which is a proxy for market value. Further, applying only 50.00 percent of the real risk-free rate to the appreciation in the fair value increment also is a conservative estimate of the return that would be required by investors. In my view, the combined effect of those two approaches is to produce a FVROR that is somewhat conservative.

As noted by Company Witness Theodore K. Wood, the FVROR discussed above is not appropriate for incremental investments to rate base. Rather, Mr. Wood derives an incremental FVROR that is more appropriate for post-rate case additions to rate base.

[76] Consistent with the method the Arizona Corporation Commission determined was appropriate in Decision No. 70665, at 31. Amounts may not add due to rounding.

XI. CONCLUSIONS AND RECOMMENDATION

Q. 70 What is your conclusion regarding the Company's Cost of Equity?

A. 70 As discussed earlier in my Direct Testimony, it is prudent and appropriate to consider multiple methodologies to arrive at an ROE recommendation for Southwest Gas. I have performed several analyses to estimate the Company's Cost of Equity and have considered several market-wide and Company-specific issues. Given those considerations, I believe that a rate of return on common equity in the range of 10.00 percent to 10.75 percent represents the range of equity investors' required rate of return for investment in natural gas utilities similar to Southwest Gas in today's capital markets. It is my view that, within that range, an ROE of 10.30 percent is reasonable and appropriate.

Lastly, as discussed earlier in my Direct Testimony, my recommendation reflects analytical results based on a proxy group of natural gas utilities. My recommendation also considers (but does not make specific adjustments for) other factors, including regulatory recovery of capital spending, and the direct costs associated with equity issuances.

Q. 71 Does this conclude your Direct Testimony?

A. 71 Yes.

APPENDIX A: PROXY GROUP SELECTION

Q. 72 How did you select the companies included in your proxy group?

A. 72 I began with the universe of companies that Value Line classifies as Natural Gas Utilities, which includes ten domestic U.S. utilities, and applied the following screening criteria:

- Because certain of the models used in my analyses assume that earnings and dividends grow over time, I excluded companies that do not consistently pay quarterly cash dividends;
- To ensure that the growth rates used in my analyses are not biased by a single analyst, all the companies in my proxy group are covered by at least two utility industry equity analysts;
- All the companies in my proxy group have investment grade senior unsecured bond and/or corporate credit ratings from S&P;
- To incorporate companies that are primarily regulated gas distribution utilities, I included companies with at least 60.00 percent of operating income derived from regulated natural gas utility operations; and
- I eliminated companies currently known to be party to a merger, or transformative transaction.

Q. 73 What companies met those screening criteria?

A. 73 The criteria discussed above resulted in a proxy group of the following seven companies:

Table 8: Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
Chesapeake Utilities Corporation[77]	CPK
New Jersey Resources Corporation	NJR
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Spire Inc.	SR

[77] Even though Chesapeake Utilities Corp. is not publicly rated by S&P, its Value Line Financial Strength Rating of B++ is comparable to the rest of the proxy group. CPK also has an National Association of Insurance Commissioners (NAIC) rating of "NAIC 1," which is equivalent to ratings in the "A" category for both Moody's and Standard & Poor's. *See* Chesapeake Utilities Corporation, Northeast Road Show, January 2018, at 16; National Association of Insurance Commissioners, CRP Credit Rating Equivalent to SVO Designations, November 2017.

APPENDIX B: COST OF COMMON EQUITY MODELS

A. Constant Growth DCF Model

Q. 74 Please more fully describe the DCF approach.

A. 74 The Constant Growth DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the Constant Growth DCF model expresses the Cost of Equity as the discount rate that sets the current price equal to expected cash flows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_t}{(1+k)^t} \quad [4]$$

where P_0 represents the current stock price, D_1 … D_t represent expected future dividends, and k is the discount rate, or required ROE. Equation [4] is a standard present value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{D(1+g)}{P_0} + g \quad [5]$$

Equation [5] often is referred to as the "Constant Growth DCF" model, in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. 75 What assumptions are required for the Constant Growth DCF model?

A. 75 The Constant Growth DCF model assumes: (1) earnings, book value, and dividends all grow at the same, constant rate in perpetuity; (2) the dividend payout ratio remains constant; (3) the Price to Earnings ("P/E") multiple remains constant in perpetuity; (4) the discount rate (that is, the estimated Cost of Equity) is greater than the expected growth rate; and (5) the calculated Cost of Equity remains constant, also in perpetuity. These simplifying assumptions, which may become more, or less, relevant as market conditions change, are required to derive the familiar Constant Growth DCF model provided in Equation [5].

Q. 76 What market data did you use to calculate the dividend yield component of your DCF model?

A. 76 The dividend yield is based on the proxy companies' current annualized dividend, and average closing stock prices over the 30-, 90-, and 180-trading day periods as of March 15, 2019.

Q. 77 Why did you use three averaging periods to calculate an average stock price?

A. 77 I did so to ensure the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably representative of expected capital market conditions over the long term. In my view, using 30-, 90-, and 180-day averaging periods reasonably balances those concerns.

Q. 78 Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. 78 Yes. Because utilities increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield.[78] That adjustment ensures the expected dividend yield is representative of the coming 12-month period and does not overstate the dividends to be paid during that time.

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[78] *See,* Exhibit No._(RBH-1).

Q. 79 Is it important to select appropriate measures of long-term growth in applying the DCF model?

A. 79 Yes. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [5] above) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, we must assume a fixed payout ratio, and that earnings per share ("EPS"), dividends per share ("DPS"), and book value per share all grow at the same constant rate in perpetuity. Because dividend growth can only be sustained by earnings growth, the model should incorporate a variety of long-term earnings growth estimates. That can be accomplished by averaging measures of long-term growth that tend to be least influenced by capital allocation decisions that companies may make in response to near-term changes in the business environment. Because such decisions may directly affect near-term dividend payout ratios, estimates of earnings growth are more indicative of long-term investor expectations than are dividend growth estimates. For the purposes of the Constant Growth DCF model, therefore, growth in EPS represents the appropriate measure of long-term growth.

Q. 80 Please summarize the findings of academic research on the appropriate measure of growth for estimating equity returns using the DCF model.

A. 80 The relationship between various growth rates and stock valuation metrics has been the subject of much academic research.[79] As noted over 40 years ago by Charles Phillips in The Economics of Regulation:

> For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to

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[79] *See,* Harris, Robert, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return,* Financial Management (Spring 1986).

> total per share earnings, so that the earnings-price ratio has assumed increased emphasis in rate cases.[80]

Subsequent academic research has clearly and consistently indicated that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[81] For example, Vander Weide and Carleton state that "[our] results … are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions."[82] Other research specifically notes the importance of analysts' growth estimates in determining the Cost of Equity, and in the valuation of equity securities. Dr. Robert Harris noted that "a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices."[83] Citing Cragg and Malkiel, Dr. Harris notes that those authors "found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based."[84] Similarly, Brigham, Shome, and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior

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[80] Charles F. Phillips, Jr., The Economics of Regulation, at 285 (Rev. ed. 1969).

[81] *See*, *e.g.*, Christofi, Christofi, Lori and Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, 21 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

[82] Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988). The Vander Weide and Carleton study was updated in 2004 under the direction of Dr. VanderWeide. The results of the updated study were consistent with the original study's conclusions.

[83] Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

[84] *Ibid*.

to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts."[85]

To that point, the research of Carleton and Vander Weide demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[86] Those findings suggest that investors form their investment decisions based on expectations of growth in earnings, not dividends. Consequently, earnings growth, not dividend growth, is the appropriate estimate for the purpose of the Constant Growth DCF model.

Q. 81 Please summarize your inputs to the Constant Growth DCF model.

A. 81 I applied the DCF model to the proxy group of natural gas utility companies using the following inputs for the price and dividend terms:

1. The average daily closing prices for the 30-, 90-, and 180-trading days ended March 15, 2019, for the term P_0; and
2. The annualized dividend per share as of March 15, 2019, for the term D_0.

I then calculated my DCF results using each of the following growth terms:

1. The Zacks consensus long-term earnings growth estimates;
2. The First Call consensus long-term earnings growth estimates;
3. The Value Line long-term earnings growth estimates; and
4. The Retention Growth estimates.

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[85] Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management (Spring 1985).

[86] *See*, Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

Q. 82 Please describe the retention growth estimate as applied in your DCF model.

A. 82 The Retention Growth model, which is a generally recognized and widely taught method of estimating long-term growth, is an alternative approach to the use of analysts' earnings growth estimates. The model estimates growth as a function of (1) expected earnings, and (2) the extent to which earnings are retained. In its simplest form, the model represents long-term growth as the product of the retention ratio (*i.e.*, the percentage of earnings not paid out as dividends (referred to below as "b") and the expected return on book equity (referred to below as "r")). Thus, the simple "b x r" form of the model projects growth as a function of internally generated funds. That form of the model is limiting, however, in that it does not provide for growth funded from external equity.

The "br + sv" form of the Retention Growth estimate used in my DCF analysis is meant to reflect growth from both internally generated funds (*i.e.*, the "br" term) and from issuances of equity (*i.e.*, the "sv" term). The first term, which is the product of the retention ratio (*i.e.*, "b", or the portion of net income not paid in dividends) and the expected Return on Equity (*i.e.*, "r") represents the portion of net income that is "plowed back" into the Company as a means of funding growth. The "sv" term is represented as:

$$\left(\frac{m}{b} - 1\right) x \ Growth \ rate \ in \ Common \ Shares \quad [6]$$

where $\frac{m}{b}$ is the Market-to-Book ratio. In this form, the "sv" term reflects an element of growth as the product of (a) the growth in shares outstanding, and (b) that portion of the market-to-book ratio that exceeds unity. As shown in Exhibit No._(RBH-2), all components of the Retention Growth model may be derived from data provided by Value Line.

Q. 83 How did you calculate the high and low DCF results?

A. 83 I calculated the proxy group median low, median, and median high DCF results by using the maximum EPS growth rate as reported by Value Line, Zacks, First Call, and the Retention Growth method for each proxy group company in combination with the dividend yield for each of the proxy companies. The proxy group median high results then reflect the median of the maximum DCF results for the proxy group as a whole. I used a similar approach to calculate the proxy group median low results using instead the minimum of the Value Line, Zacks, First Call, and Retention Growth method growth rates for each company. For the purposes of my Direct Testimony, I have put more emphasis on the median results of my Constant Growth DCF analysis, because the mean results are affected by an anomalously high growth rate for Northwest Natural Gas Company of 25.50 percent from Value Line due to the company's significant losses in 2017.

Q. 84 What are the results of your DCF analysis?

A. 84 The results of my CAPM analysis are summarized in Table 9 below (*see* also Exhibit No._(RBH-1)).

Table 9: Constant Growth DCF Results[87]

	Median	Median High
30-Day Average	9.61%	12.33%
90-Day Average	9.68%	12.38%
180-Day Average	9.71%	12.42%

[87] *See* also, Exhibit No._(RBH-1).

B. CAPM Analysis

Q. 85 Please describe the general form of the CAPM analysis.

A. 85 The CAPM analysis is a risk premium method that estimates the Cost of Equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). The CAPM describes the relationship between a security's investment risk and the market rate of return. The CAPM assumes that all other risk, *i.e.*, all non-market or unsystematic risk, can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors require compensation only for systematic risk that is the result of macroeconomic and other events that affect the returns on all assets.

As shown in Equation [7], below, the CAPM is defined by four components, each of which theoretically must be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [7]$$

where:

k = the required market ROE for a security;

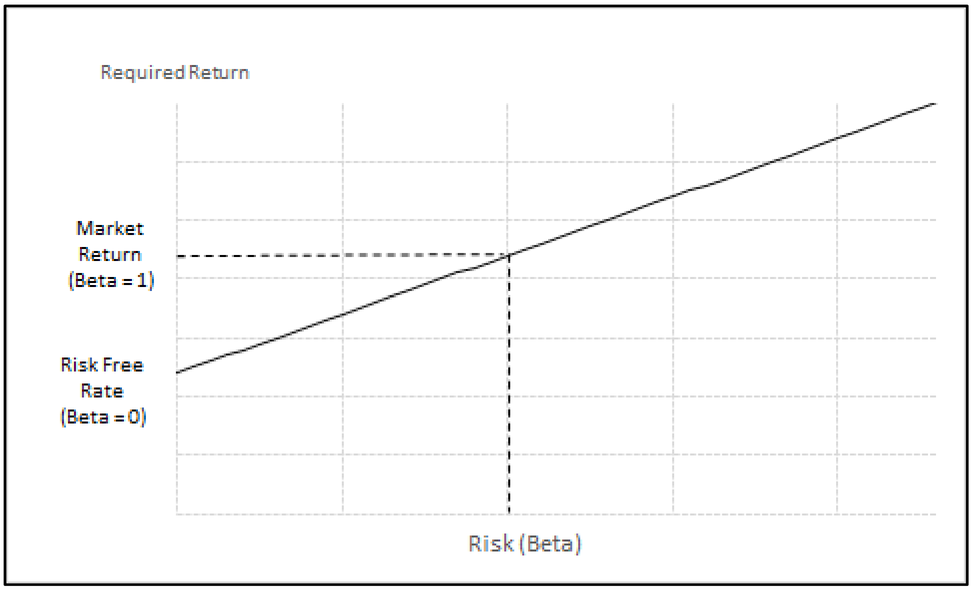
β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

Equation [7] describes the Security Market Line ("SML"), or the CAPM risk-return relationship, which is graphically depicted in Chart 7 below. The intercept is the risk-free rate (r_f) which has a Beta coefficient of zero, the slope is the expected market risk premium ($r_m – r_f$). By definition, r_m, the return on the market has a Beta coefficient of 1.00. CAPM states that in well-behaving capital markets, the expected equity risk premium on a given security is proportional to its Beta coefficient.

Chart 7: Security Market Line



Intuitively, higher Beta coefficients indicate the subject company's returns have been relatively volatile and have moved in tandem with the overall market. Consequently, if a company has a Beta coefficient of 1.00, it is as risky as the market and does not provide any diversification benefit.

In Equation [7], the term (r_m – r_f) represents the Market Risk Premium.[88] According to the theory underlying the CAPM, since unsystematic risk can be diversified away by adding securities to their investment portfolios, the market will not compensate investors for bearing that risk. Therefore, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

[88] The Market Risk Premium is defined as the incremental return of the market over the risk-free rate.

$$\beta_j = \frac{\sigma_j}{\sigma_m} \, x \, \rho_{j,m} \quad [8]$$

where σ_j is the standard deviation of returns for company "*j*"; σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns in between company *j* and the broad market. The Beta coefficient therefore represents both relative volatility (*i.e.*, the standard deviation) of returns, and the correlation in returns between the subject company and the overall market.

Q. 86 What assumptions did you include in your CAPM analysis?

A. 86 Because utility equity is a long duration investment, I used three different estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (*i.e.*, 3.03 percent)[89]; (2) the near-term projected 30-year Treasury yield (*i.e.*, 3.25 percent);[90] and (3) the long-term projected 30-year Treasury yield (*i.e.*, 4.05 percent).[91]

Q. 87 Why have you relied on the 30-year treasury yield for your CAPM analysis?

A. 87 In determining the security most relevant to the application of the CAPM, it is important to select the term (or maturity) that best matches the life of the underlying investment. Because utility equity has a perpetual life, the 30-year Treasury yield is the appropriate measure of the risk-free rate.

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[89] Bloomberg Professional Services.

[90] *See,* Blue Chip Financial Forecasts, Vol. 38, No. 3, March 1, 2019, at 2. Consensus projections of the 30-year Treasury yield for the six quarters ending June 2020.

[91] *See,* Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14. Consensus projections of the 30-year Treasury yield for the periods 2020-2024 and 2025-2029.

Q. 88 Please describe your *ex-ante* approach to estimating the market risk premium.

A. 88 The approach is based on the market required return, less the current 30-year Treasury bond yield. To estimate the market required return, I calculated the market capitalization weighted average ROE based on the Constant Growth DCF model. To do so, I relied on data from Bloomberg and Value Line, respectively. With respect to Bloomberg-derived growth estimates, I calculated the expected dividend yield (using the same one-half growth rate assumption described earlier) and combined that amount with the projected earnings growth rate to arrive at the market capitalization weighted average DCF result. I performed that calculation for each of the companies for which Bloomberg provided both dividend yields and consensus growth rates. I then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived *ex-ante* market risk premium estimate. In the case of Value Line, I performed the same calculation, again using all companies for which five-year earnings growth rates were available. The results of those calculations are provided in Exhibit No._(RBH-3).

Q. 89 How did you apply your expected market risk premium and risk-free rate estimates?

A. 89 I relied on each of the *ex-ante* Market Risk Premiums discussed above, together with the current, near-term projected, and long-term projected 30-year Treasury bond yields as inputs to my CAPM analysis.

Q. 90 What Beta coefficients did you use in your CAPM model?

A. 90 As shown in Exhibit No._(RBH-4), I considered the Beta coefficients reported by Value Line and Bloomberg, both of which adjust their calculated (or raw) Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00. A notable difference between the two is that Value Line calculates the Beta coefficient over a five-year period, whereas Bloomberg's calculation is based on two years of data.

Q. 91 What are the results of your CAPM analysis?

A. 91 The results of my CAPM analysis are summarized in Table 10 below (*see* also, Exhibit No._(RBH-5)).

Table 10: Summary of CAPM Results

C.

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.03%)	9.12%	10.90%
Near Term Projected 30-Year Treasury (3.25%)	9.34%	11.12%
Long Term Projected 30-Year Treasury (4.05%)	10.14%	11.92%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.03%)	10.31%	12.44%
Near Term Projected 30-Year Treasury (3.25%)	10.52%	12.66%
Long Term Projected 30-Year Treasury (4.05%)	11.32%	13.46%

Bond Yield Plus Risk Premium Approach

Q. 92 Please describe the Bond Yield Plus Risk Premium approach.

A. 92 This approach is based on the basic financial tenet that equity investors bear the residual risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders are riskier than returns to bondholders, equity investors must be compensated for bearing that additional risk. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of the equity risk premium and the yield on a particular class of bonds. Because the Equity Risk Premium is not directly observable, it typically is estimated using a variety of approaches, some of which incorporate *ex-ante*, or forward-looking, estimates of the Cost of Equity, and others that consider historical, or *ex-post*, estimates. An alternative approach is to use actual authorized returns for gas distribution companies to estimate the Equity Risk Premium.

Q. 93 Please explain how you performed your Bond Yield Plus Risk Premium analysis.

A. 93 As suggested above, I first defined the Risk Premium as the difference between authorized ROEs and the then-prevailing level of long-term (*i.e.*, 30-year) Treasury yields. I then gathered data from 1,117 natural gas rate proceedings between January 1, 1980 and March 15, 2019. I also calculated the average period between the filing of the case and the date of the final order (that is, the lag period). To reflect the prevailing level of interest rates during the pendency of the proceedings, I calculated the average 30-year Treasury yield over the average lag period (approximately 187 days).

Because the data covers several economic cycles,[92] the analysis also may be used to assess the stability of the Equity Risk Premium. As noted above, the Equity Risk Premium is not constant over time; prior research has shown it is directly related to expected market volatility, and inversely related to the level of

[92] *See,* National Bureau of Economic Research, U.S. Business Cycle Expansion and Contractions.

interest rates.[93] That finding is particularly relevant given the relatively low level of current Treasury yields.

Q. 94 How did you model the relationship between interest rates and the equity risk premium?

A. 94 The basic method used was regression analysis, in which the observed Equity Risk Premium is the dependent variable, and the average 30-year Treasury yield is the independent variable. Relative to the long-term historical average, the analytical period includes interest rates and authorized ROEs that are quite high during one period (*i.e.*, the 1980s) and that are quite low during another (*i.e.*, the post-Lehman bankruptcy period). To account for that variability, I used the semi-log regression, in which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \alpha + \beta(LN(T_{30}) \quad [10]$$

As shown on Chart 8 (below), the semi-log form is useful when measuring an absolute change in the dependent variable (in this case, the Risk Premium) relative to a proportional change in the independent variable (the 30-year Treasury yield).

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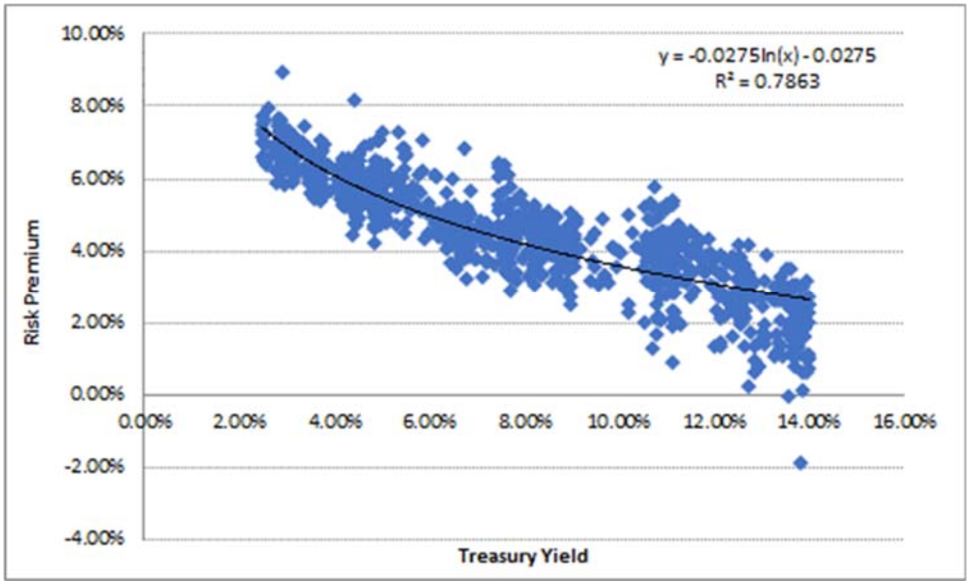
[93] *See*, *e.g.*, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, Summer 1992, at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, Autumn 1995, at 89-95.

Chart 8: Equity Risk Premium



As Chart 8 demonstrates, over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. An important consequence of that relationship is that simply applying the long-term average Equity Risk Premium of 4.69 percent would significantly understate the Cost of Equity. Based on the regression coefficients in Chart 8, however, the implied ROE is between 9.89 percent and 10.11 percent (*see* Exhibit No._(RBH-6) and Table 11, below).

Table 11: Bond Yield Plus Risk Premium Results

Treasury Yield	Return on Equity
Current 30-Year Treasury (3.03%)	9.89%
Near Term Projected 30-Year Treasury (3.25%)	9.91%
Long Term Projected 30-Year Treasury (4.05%)	10.11%

D. Expected Earnings Analysis

Q. 95 Please describe the Expected Earnings analysis.

A. 95 The Expected Earnings analysis is based on the principle of opportunity costs. Because investors may invest in, and earn returns on alternative investments of similar risk, those rates of return can provide a useful benchmark in determining the appropriate rate of return for a firm. Further, because those results are based solely on the returns expected by investors, exclusive of market-data or models, the Expected Earnings approach provides a direct comparison.

Q. 96 Please explain how the Expected Earnings analysis is conducted.

A. 96 The Expected Earnings analysis typically takes the actual earnings on book value of investment for each of the members of the proxy group and compares those values to the rate of return in question. Although the traditional approach uses data based on historical accounting records, it is common to use forecasted data in conducting the analysis. Projected returns on book investment are provided by various industry publications (*e.g.,* Value Line), which I have used in my analysis.

I relied on Value Line's projected Return on Common Equity for the period 2021-2023, and adjusted those projected returns to account for the fact that they reflect common shares outstanding at the end of the period, rather than the average shares outstanding over the course of the year.[94] The results range

[94] The rationale for that adjustment is straightforward: Earnings are achieved over the course of a year, and should be related to the equity that was, on average, in place during that year. See, Leopold A. Bernstein, Financial Statement Analysis: Theory, Application, and Interpretation, Irwin, 4th Ed., 1988, at 630.

from 10.05 percent to 12.13 percent, with a median value of 10.57 percent (*see,* Exhibit No._(RBH-7)).

Resume of:
Robert B. Hevert, Partner
Rates, Regulation & Planning Practice Leader

Summary

Bob Hevert is a financial and economic consultant with more than 30 years of broad experience in the energy and utility industries. He has an extensive background in the areas of corporate finance, mergers and acquisitions, project finance, asset and business unit valuation, rate and regulatory matters, energy market assessment, and corporate strategic planning. He has provided expert testimony on a wide range of financial, strategic, and economic matters on more than 250 occasions at the state, provincial, and federal levels.

Prior to joining ScottMadden, Bob served as managing partner at Sussex Economic Advisors, LLC. Throughout the course of his career, he has worked with numerous leading energy companies and financial institutions throughout North America. He has provided expert testimony and support of litigation in various regulatory proceedings on a variety of energy and economic issues. Bob earned a B.S. in business and economics from the University of Delaware and an M.B.A. with a concentration in finance from the University of Massachusetts at Amherst. Bob also holds the Chartered Financial Analyst designation.

Areas of Specialization

- Regulation and rates
- Utilities
- Fossil/hydro generation
- Markets and RTOs
- Nuclear generation
- Mergers and acquisitions
- Regulatory strategy and rate case support
- Capital project planning
- Strategic and business planning

Recent Expert Testimony Submission/Appearance

- Federal Energy Regulatory Commission – Return on Equity
- New Jersey Board of Public Utilities – Merger Approval
- New Mexico Public Regulation Commission – Cost of Capital and Financial Integrity
- United States District Court – PURPA and FERC Regulations
- Alberta Utilities Commission – Return on Equity and Capital Structure

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies, the Alberta Utilities Commission, and the Federal Energy Regulatory Commission
- For an independent electric transmission provider in Texas, prepared an expert report on the economic damages with respect to failure to meet guaranteed completion dates. The report was filed as part of an arbitration proceeding and included a review of the ratemaking implications of economic damages
- Advised the board of directors of a publicly traded electric and natural gas combination utility on dividend policy issues, earnings payout trends and related capital market considerations
- Assisted a publicly traded utility with a strategic buy-side evaluation of a gas utility with more than $1 billion in assets. The assignment included operational performance benchmarking, calculation of merger synergies, risk analysis, and review of the regulatory implications of the transaction
- Provided testimony before the Arkansas Public Service Commission in support of the acquisition of SourceGas LLC by Black Hills Corporation. The testimony addressed certain balance sheet capitalization and credit rating issues
- For the State of Maine Public Utility Commission, prepared a report that summarized the Northeast and Atlantic Canada natural gas power markets and analyzed the potential benefits and costs associated with natural gas pipeline expansions. The independent report was filed at the Maine Public Utility Commission

scottmadden
MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Regulatory Commission of Alaska				
Cook Inlet Natural Gas Storage Alaska, LLC	06/18	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. U-18-043	Return on Equity
ENSTAR Natural Gas Company	06/16	ENSTAR Natural Gas Company	Matter No. TA 285-4	Return on Equity
ENSTAR Natural Gas Company	08/14	ENSTAR Natural Gas Company	Matter No. TA 262-4	Return on Equity
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	10/17	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	2018 General Cost of Capital, Proceeding ID. 22570	Rate of Return
EPCOR Energy Alberta G.P. Inc.	01/17	EPCOR Energy Alberta G.P. Inc.	Proceeding 22357	Energy Price Setting Plan
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/16	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2016 General Cost of Capital, Proceeding ID. 20622	Rate of Return
Arizona Corporation Commission				
Southwest Gas Corporation	05/16	Southwest Gas Corporation	Docket No. G-01551A-16-0107	Return on Equity
Southwest Gas Corporation	11/10	Southwest Gas Corporation	Docket No. G-01551A-10-0458	Return on Equity
Arkansas Public Service Commission				
Southwestern Electric Power Company	02/19	Southwestern Electric Power Company	Docket No. 19-008-U	Return on Equity
Oklahoma Gas and Electric Company	09/16	Oklahoma Gas and Electric Company	Docket No. 16-052-U	Return on Equity
SourceGas Arkansas, Inc.	12/15	SourceGas Arkansas, Inc.	Docket No. 15-078-U	Response to Direct Testimony by Arkansas Attorney General related to Compliance Issues
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	11/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 15-098-U	Return on Equity
SourceGas Arkansas, Inc.	04/15	SourceGas Arkansas, Inc.	Docket No. 15-011-U	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	01/07	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 06-161-U	Return on Equity
California Public Utilities Commission				
Southwest Gas Corporation	12/12	Southwest Gas Corporation	Docket No. A-12-12-024	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Return on Equity
Xcel Energy, Inc.	03/15	Public Service Company of Colorado	Docket No. 15AL-0135G	Return on Equity (gas)
Xcel Energy, Inc.	06/14	Public Service Company of Colorado	Docket No. 14AL-0660E	Return on Equity (electric)

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MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Xcel Energy, Inc.	12/12	Public Service Company of Colorado	Docket No. 12AL-1268G	Return on Equity (gas)
Xcel Energy, Inc.	11/11	Public Service Company of Colorado	Docket No. 11AL-947E	Return on Equity (electric)
Xcel Energy, Inc.	12/10	Public Service Company of Colorado	Docket No. 10AL-963G	Return on Equity (electric)
Atmos Energy Corporation	07/09	Atmos Energy Colorado-Kansas Division	Docket No. 09AL-507G	Return on Equity (gas)
Xcel Energy, Inc.	12/06	Public Service Company of Colorado	Docket No. 06S-656G	Return on Equity (gas)
Xcel Energy, Inc.	04/06	Public Service Company of Colorado	Docket No. 06S-234EG	Return on Equity (electric)
Xcel Energy, Inc.	08/05	Public Service Company of Colorado	Docket No. 05S-369ST	Return on Equity (steam)
Xcel Energy, Inc.	05/05	Public Service Company of Colorado	Docket No. 05S-246G	Return on Equity (gas)
Connecticut Public Utilities Regulatory Authority				
Connecticut Light and Power Company	11/17	Connecticut Light and Power Company	Docket No. 17-10-46	Return on Equity
Connecticut Light and Power Company	06/14	Connecticut Light and Power Company	Docket No. 14-05-06	Return on Equity
Southern Connecticut Gas Company	09/08	Southern Connecticut Gas Company	Docket No. 08-08-17	Return on Equity
Southern Connecticut Gas Company	12/07	Southern Connecticut Gas Company	Docket No. 05-03-17PH02	Return on Equity
Connecticut Natural Gas Corporation	12/07	Connecticut Natural Gas Corporation	Docket No. 06-03-04PH02	Return on Equity
Council of the City of New Orleans				
Entergy New Orleans, LLC	09/18	Entergy New Orleans, LLC	Docket No. UD-18-07	Return on Equity
Delaware Public Service Commission				
Delmarva Power & Light Company	08/17	Delmarva Power & Light Company	Docket No. 17-0977 (Electric)	Return on Equity
Delmarva Power & Light Company	08/17	Delmarva Power & Light Company	Docket No. 17-0978 (Gas)	Return on Equity
Delmarva Power & Light Company	05/16	Delmarva Power & Light Company	Case No. 16-649 (Electric)	Return on Equity
Delmarva Power & Light Company	05/16	Delmarva Power & Light Company	Case No. 16-650 (Gas)	Return on Equity
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 13-115	Return on Equity
Delmarva Power & Light Company	12/12	Delmarva Power & Light Company	Case No. 12-546	Return on Equity
Delmarva Power & Light Company	03/12	Delmarva Power & Light Company	Case No. 11-528	Return on Equity
District of Columbia Public Service Commission				
Potomac Electric Power Company	12/17	Potomac Electric Power Company	Formal Case No. 1150	Return on Equity
Potomac Electric Power Company	06/16	Potomac Electric Power Company	Formal Case No. 1139	Return on Equity
Washington Gas Light Company	02/16	Washington Gas Light Company	Formal Case No. 1137	Return on Equity
Potomac Electric Power Company	03/13	Potomac Electric Power Company	Formal Case No. 1103-2013-E	Return on Equity

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MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Potomac Electric Power Company	07/11	Potomac Electric Power Company	Formal Case No. 1087	Return on Equity
Federal Energy Regulatory Commission				
Sabine Pipeline, LLC	09/15	Sabine Pipeline, LLC	Docket No. RP15-1322-000	Return on Equity
NextEra Energy Transmission West, LLC	07/15	NextEra Energy Transmission West, LLC	Docket No. ER15-2239-000	Return on Equity
Maritimes & Northeast Pipeline, LLC	05/15	Maritimes & Northeast Pipeline, LLC	Docket No. RP15-1026-000	Return on Equity
Public Service Company of New Mexico	12/12	Public Service Company of New Mexico	Docket No. ER13-685-000	Return on Equity
Public Service Company of New Mexico	10/10	Public Service Company of New Mexico	Docket No. ER11-1915-000	Return on Equity
Portland Natural Gas Transmission System	05/10	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Return on Equity
Florida Gas Transmission Company, LLC	10/09	Florida Gas Transmission Company, LLC	Docket No. RP10-21-000	Return on Equity
Maritimes and Northeast Pipeline, LLC	07/09	Maritimes and Northeast Pipeline, LLC	Docket No. RP09-809-000	Return on Equity
Spectra Energy	02/08	Saltville Gas Storage	Docket No. RP08-257-000	Return on Equity
Panhandle Energy Pipelines	08/07	Panhandle Energy Pipelines	Docket No. PL07-2-000	Response to draft policy statement regarding inclusion of MLPs in proxy groups for determination of gas pipeline ROEs
Southwest Gas Storage Company	08/07	Southwest Gas Storage Company	Docket No. RP07-541-000	Return on Equity
Southwest Gas Storage Company	06/07	Southwest Gas Storage Company	Docket No. RP07-34-000	Return on Equity
Sea Robin Pipeline LLC	06/07	Sea Robin Pipeline LLC	Docket No. RP07-513-000	Return on Equity
Transwestern Pipeline Company	09/06	Transwestern Pipeline Company	Docket No. RP06-614-000	Return on Equity
GPU International and Aquila	11/00	GPU International	Docket No. EC01-24-000	Market Power Study
Florida Public Service Commission				
Florida Power & Light Company	03/16	Florida Power & Light Company	Docket No. 160021-EI	Return on Equity
Tampa Electric Company	04/13	Tampa Electric Company	Docket No. 130040-EI	Return on Equity
Georgia Public Service Commission				
Atlanta Gas Light Company	05/10	Atlanta Gas Light Company	Docket No. 31647-U	Return on Equity
Hawaii Public Utilities Commission				
Hawai'i Electric Light Company, Inc.	12/18	Hawai'i Electric Light Company, Inc.	Docket No. 2018-0368	Return on Equity
Maui Electric Company, Limited	10/17	Maui Electric Company, Limited	Docket No. 2017-0150	Return on Equity
Hawaiian Electric Company, Inc.	12/16	Hawaiian Electric Company, Inc.	Docket No. 2016-0328	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Hawai'i Electric Light Company, Inc.	09/16	Hawai'i Electric Light Company, Inc.	Docket No. 2015-0170	Return on Equity
Maui Electric Company, Limited	12/14	Maui Electric Company, Limited	Docket No. 2014-0318	Return on Equity
Hawaiian Electric Company, Inc.	06/14	Hawaiian Electric Company, Inc.	Docket No. 2013-0373	Return on Equity
Hawai'i Electric Light Company, Inc.	08/12	Hawai'i Electric Light Company, Inc.	Docket No. 2012-0099	Return on Equity
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	01/18	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 18-0463	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/15	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 15-0142	Return on Equity
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	04/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Docket No. 14-0371	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/13	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 13-0192	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0279	Return on Equity (electric)
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0282	Return on Equity (gas)
Indiana Utility Regulatory Commission				
Indiana Michigan Power Company	7/17	Indiana Michigan Power Company	Cause No. 44967	Return on Equity
Duke Energy Indiana, Inc.	12/15	Duke Energy Indiana, Inc.	Cause No. 44720	Return on Equity
Duke Energy Indiana, Inc.	12/14	Duke Energy Indiana, Inc.	Cause No. 44526	Return on Equity
Northern Indiana Public Service Company	05/09	Northern Indiana Public Service Company	Cause No. 43894	Assessment of Valuation Approaches
Kansas Corporation Commission				
Empire District Electric Company	02/19	Empire District Electric Company	Docket No. 19-EPDE-223-RTS	Return on Equity
Empire District Electric Company	12/18	Empire District Electric Company	Docket No. 19-EPDE-223-RTS	Alternative Ratemaking Mechanisms
Kansas City Power & Light Company	05/18	Kansas City Power & Light Company	Docket No. 18-KCPE-480-RTS	Return on Equity
Westar Energy	02/18	Westar Energy	Docket No. 18-WSEE-328-RTS	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Great Plains Energy, Inc. and Kansas City Power & Light Company	01/17	Great Plains Energy, Inc. and Kansas City Power & Light Company	Docket No. 16-KCPE-593-ACQ	Response to Direct Testimony by Commission Staff related to the ratemaking capital structure processes
Kansas City Power & Light Company	01/15	Kansas City Power & Light Company	Docket No. 15-KCPE-116-RTS	Return on Equity
Maine Public Utilities Commission				
Northern Utilities, Inc.	05/17	Northern Utilities, Inc.	Docket No. 2017-00065	Return on Equity
Central Maine Power Company	06/11	Central Maine Power Company	Docket No. 2010-327	Response to Bench Analysis provided by Commission Staff relating to the Company's credit and collections processes
Maryland Public Service Commission				
Potomac Electric Power Company	01/19	Potomac Electric Power Company	Case No. 9602	Return on Equity
Washington Gas Light Company	05/18	Washington Gas Light Company	Case No. 9481	Return on Equity
Potomac Electric Power Company	01/18	Potomac Electric Power Company	Case No. 9472	Return on Equity
Delmarva Power & Light Company	07/17	Delmarva Power & Light Company	Case No. 9455	Return on Equity
Potomac Electric Power Company	03/17	Potomac Electric Power Company	Case No. 9443	Return on Equity
Delmarva Power & Light Company	06/16	Delmarva Power & Light Company	Case No. 9424	Return on Equity
Potomac Electric Power Company	06/16	Potomac Electric Power Company	Case No. 9418	Return on Equity
Potomac Electric Power Company	12/13	Potomac Electric Power Company	Case No. 9336	Return on Equity
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 9317	Return on Equity
Potomac Electric Power Company	11/12	Potomac Electric Power Company	Case No. 9311	Return on Equity
Potomac Electric Power Company	12/11	Potomac Electric Power Company	Case No. 9286	Return on Equity
Delmarva Power & Light Company	12/11	Delmarva Power & Light Company	Case No. 9285	Return on Equity
Delmarva Power & Light Company	12/10	Delmarva Power & Light Company	Case No. 9249	Return on Equity
Massachusetts Department of Public Utilities				
NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	02/19	NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	DPU 18-64/DPU 18-65/DPU 18-66	Response to Direct Testimony by Attorney General Witness regarding Remuneration Rate Section 83D

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
National Grid	11/18	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 18-150	Return on Equity
NSTAR Electric Company d/b/a Eversource Energy	11/18	NSTAR Electric Company d/b/a Eversource Energy	DPU 18-76/DPU 18-77/DPU 18-78	Response to Direct Testimony by Attorney General Witness regarding Remuneration Rate Section 83C
Boston Gas Company, Colonial Gas Company each d/b/a National Grid	11/17	Boston Gas Company, Colonial Gas Company each d/b/a National Grid	DPU 17-170	Return on Equity
NSTAR Electric Company Western and Massachusetts Electric Company each d/b/a Eversource Energy	01/17	NSTAR Electric Company Western Massachusetts Electric Company each d/b/a Eversource Energy	DPU 17-05	Return on Equity
National Grid	11/15	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 15-155	Return on Equity
Fitchburg Gas and Electric Light Company d/b/a Unitil	06/15	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 15-80	Return on Equity
NSTAR Gas Company	12/14	NSTAR Gas Company	DPU 14-150	Return on Equity
Fitchburg Gas and Electric Light Company d/b/a Unitil	07/13	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 13-90	Return on Equity
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	04/12	Bay State Gas Company d/b/a Columbia Gas of Massachusetts	DPU 12-25	Capital Cost Recovery
National Grid	08/09	Massachusetts Electric Company d/b/a National Grid	DPU 09-39	Revenue Decoupling and Return on Equity
National Grid	08/09	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 09-38	Return on Equity – Solar Generation
Bay State Gas Company	04/09	Bay State Gas Company	DPU 09-30	Return on Equity
NSTAR Electric	09/04	NSTAR Electric	DTE 04-85	Divestiture of Power Purchase Agreement
NSTAR Electric	08/04	NSTAR Electric	DTE 04-78	Divestiture of Power Purchase Agreement

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
NSTAR Electric	07/04	NSTAR Electric	DTE 04-68	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-61	Divestiture of Power Purchase Agreement
NSTAR Electric	06/04	NSTAR Electric	DTE 04-60	Divestiture of Power Purchase Agreement
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Bay State Gas Company	01/93	Bay State Gas Company	DPU 93-14	Divestiture of Shelf Registration
Bay State Gas Company	01/91	Bay State Gas Company	DPU 91-25	Divestiture of Shelf Registration
Michigan Public Service Commission				
Indiana Michigan Power Company	05/17	Indiana Michigan Power Company	Case No. U-18370	Return on Equity
Minnesota Public Utilities Commission				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/17	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-17-285	Return on Equity
ALLETE, Inc., d/b/a Minnesota Power Inc.	11/16	ALLETE, Inc., d/b/a Minnesota Power Inc.	Docket No. E015/GR-16-664	Return on Equity
Otter Tail Power Corporation	02/16	Otter Tail Power Company	Docket No. E017/GR-15-1033	Return on Equity
Minnesota Energy Resources Corporation	09/15	Minnesota Energy Resources Corporation	Docket No. G-011/GR-15-736	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-15-424	Return on Equity
Xcel Energy, Inc.	11/13	Northern States Power Company	Docket No. E002/GR-13-868	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/13	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-13-316	Return on Equity
Xcel Energy, Inc.	11/12	Northern States Power Company	Docket No. E002/GR-12-961	Return on Equity
Otter Tail Power Corporation	04/10	Otter Tail Power Company	Docket No. E-017/GR-10-239	Return on Equity
Minnesota Power a division of ALLETE, Inc.	11/09	Minnesota Power	Docket No. E-015/GR-09-1151	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	11/08	CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-08-1075	Return on Equity
Otter Tail Power Corporation	10/07	Otter Tail Power Company	Docket No. E-017/GR-07-1178	Return on Equity
Xcel Energy, Inc.	11/05	Northern States Power Company -Minnesota	Docket No. E-002/GR-05-1428	Return on Equity (electric)

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MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Xcel Energy, Inc.	09/04	Northern States Power Company - Minnesota	Docket No. G-002/GR-04-1511	Return on Equity (gas)
Mississippi Public Service Commission				
CenterPoint Energy Resources, Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Mississippi Gas	07/09	CenterPoint Energy Mississippi Gas	Docket No. 09-UN-334	Return on Equity
Missouri Public Service Commission				
Union Electric Company d/b/a Ameren Missouri	12/18	Union Electric Company d/b/a Ameren Missouri	Case No. GR-2019-0077	Return on Equity
KCP&L Greater Missouri Operations Company	01/18	KCP&L Greater Missouri Operations Company	Case No. ER-2018-0146	Return on Equity
Kansas City Power & Light Company	01/18	Kansas City Power & Light Company	Case No. ER-2018-0145	Return on Equity
Laclede Gas Company and Missouri Gas Energy	11/17	Laclede Gas Company and Missouri Gas Energy	Case No. GR-2017-0215 Case No. GR-2017-0216	Goodwill Adjustment on Capital Structure
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a/ Liberty Utilities	09/17	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a/ Liberty Utilities	Case No. GR-2018-0013	New Ratemaking Mechanisms
Union Electric Company d/b/a Ameren Missouri	07/16	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2016-0179	Return on Equity (electric)
Kansas City Power & Light Company	07/16	Kansas City Power & Light Company	Case No. ER-2016-0285	Return on Equity (electric)
Kansas City Power & Light Company	02/16	Kansas City Power & Light Company	Case No. ER-2016-0156	Return on Equity (electric)
Kansas City Power & Light Company	10/14	Kansas City Power & Light Company	Case No. ER-2014-0370	Return on Equity (electric)
Union Electric Company d/b/a Ameren Missouri	07/14	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2014-0258	Return on Equity (electric)
Union Electric Company d/b/a Ameren Missouri	06/14	Union Electric Company d/b/a Ameren Missouri	Case No. EC-2014-0223	Return on Equity (electric)
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	02/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Case No. GR-2014-0152	Return on Equity
Laclede Gas Company	12/12	Laclede Gas Company	Case No. GR-2013-0171	Return on Equity
Union Electric Company d/b/a Ameren Missouri	02/12	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2012-0166	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	09/10	Union Electric Company d/b/a AmerenUE	Case No. ER-2011-0028	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	06/10	Union Electric Company d/b/a AmerenUE	Case No. GR-2010-0363	Return on Equity (gas)

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Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Montana Public Service Commission				
Northwestern Corporation	09/12	Northwestern Corporation d/b/a Northwestern Energy	Docket No. D2012.9.94	Return on Equity (gas)
Nevada Public Utilities Commission				
Southwest Gas Corporation	05/18	Southwest Gas Corporation	Docket No. 18-05031	Return on Equity (gas)
Southwest Gas Corporation	04/12	Southwest Gas Corporation	Docket No. 12-04005	Return on Equity (gas)
Nevada Power Company	06/11	Nevada Power Company	Docket No. 11-06006	Return on Equity (electric)
New Hampshire Public Utilities Commission				
Northern Utilities, Inc.	06/17	Northern Utilities, Inc.	Docket No. DG 17-070	Return on Equity
Liberty Utilities d/b/a EnergyNorth Natural Gas	04/17	Liberty Utilities d/b/a EnergyNorth Natural Gas	Docket No. DG 17-048	Return on Equity
Unitil Energy Systems, Inc.	04/16	Unitil Energy Systems, Inc.	Docket No. DE 16-384	Return on Equity
Liberty Utilities d/b/a Granite State Electric Company	04/16	Liberty Utilities d/b/a Granite State Electric Company	Docket No. DE 16-383	Return on Equity
Liberty Utilities d/b/a EnergyNorth Natural Gas	08/14	Liberty Utilities d/b/a EnergyNorth Natural Gas	Docket No. DG 14-180	Return on Equity
Liberty Utilities d/b/a Granite State Electric Company	03/13	Liberty Utilities d/b/a Granite State Electric Company	Docket No. DE 13-063	Return on Equity
EnergyNorth Natural Gas d/b/a National Grid NH	02/10	EnergyNorth Natural Gas d/b/a National Grid NH	Docket No. DG 10-017	Return on Equity
Unitil Energy Systems, Inc., EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	08/08	Unitil Energy Systems, Inc., EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	Docket No. DG 07-072	Carrying Charge Rate on Cash Working Capital
New Jersey Board of Public Utilities				
Atlantic City Electric Company	10/18	Atlantic City Electric Company	Docket No. EO18020196	Return on Equity
Atlantic City Electric Company	08/18	Atlantic City Electric Company	Docket No. ER18080925	Return on Equity
Atlantic City Electric Company	06/18	Atlantic City Electric Company	Docket No. ER18060638	Return on Equity
Atlantic City Electric Company	03/17	Atlantic City Electric Company	Docket No. ER17030308	Return on Equity

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Sponsor	Date	Case/Applicant	Docket No.	Subject
Pivotal Utility Holdings, Inc.	08/16	Elizabethtown Gas	Docket No. GR16090826	Return on Equity
The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	04/16	The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	BPU Docket No. GM15101196	Merger Approval
Atlantic City Electric Company	03/16	Atlantic City Electric Company	Docket No. ER16030252	Return on Equity
Pepco Holdings, Inc.	03/14	Atlantic City Electric Company	Docket No. ER14030245	Return on Equity
Orange and Rockland Utilities	11/13	Rockland Electric Company	Docket No. ER13111135	Return on Equity
Atlantic City Electric Company	12/12	Atlantic City Electric Company	Docket No. ER12121071	Return on Equity
Atlantic City Electric Company	08/11	Atlantic City Electric Company	Docket No. ER11080469	Return on Equity
Pepco Holdings, Inc.	09/06	Atlantic City Electric Company	Docket No. EM06090638	Divestiture and Valuation of Electric Generating Assets
Pepco Holdings, Inc.	12/05	Atlantic City Electric Company	Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Conectiv	06/03	Atlantic City Electric Company	Docket No. EO03020091	Market Value of Electric Generation Assets; Auction Process
New Mexico Public Regulation Commission				
Public Service Company of New Mexico	12/16	Public Service Company of New Mexico	Case No. 16-00276-UT	Return on Equity (electric)
Public Service Company of New Mexico	08/15	Public Service Company of New Mexico	Case No. 15-00261-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 14-00332-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 13-00390-UT	Cost of Capital and Financial Integrity
Southwestern Public Service Company	02/11	Southwestern Public Service Company	Case No. 10-00395-UT	Return on Equity (electric)
Public Service Company of New Mexico	06/10	Public Service Company of New Mexico	Case No. 10-00086-UT	Return on Equity (electric)
Public Service Company of New Mexico	09/08	Public Service Company of New Mexico	Case No. 08-00273-UT	Return on Equity (electric)
Xcel Energy, Inc.	07/07	Southwestern Public Service Company	Case No. 07-00319-UT	Return on Equity (electric)
New York State Public Service Commission				
Consolidated Edison Company of New York, Inc.	01/15	Consolidated Edison Company of New York, Inc.	Case No. 15-E-0050	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	11/14	Orange and Rockland Utilities, Inc.	Case Nos. 14-E-0493 and 14-G-0494	Return on Equity (electric and gas)

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Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Consolidated Edison Company of New York, Inc.	01/13	Consolidated Edison Company of New York, Inc.	Case No. 13-E-0030	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Electric Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Electric Service	Case No. 12-E-0201	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Gas Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Gas Service	Case No. 12-G-0202	Return on Equity (gas)
Orange and Rockland Utilities, Inc.	07/11	Orange and Rockland Utilities, Inc.	Case No. 11-E-0408	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	07/10	Orange and Rockland Utilities, Inc.	Case No. 10-E-0362	Return on Equity (electric)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-G-0795	Return on Equity (gas)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-S-0794	Return on Equity (steam)
Niagara Mohawk Power Corporation	07/01	Niagara Mohawk Power Corporation	Case No. 01-E-1046	Power Purchase and Sale Agreement; Standard Offer Service Agreement
North Carolina Utilities Commission				
Piedmont Natural Gas Company, Inc.	04/19	Piedmont Natural Gas Company, Inc.	Docket No. G-9, Sub 743	Return on Equity
Virginia Electric and Power Company d/b/a Dominion North Carolina Power	03/19	Virginia Electric and Power Company d/b/a Dominion North Carolina Power	Docket No. E-22, Sub 562	Return on Equity
Duke Energy Carolinas, LLC	08/17	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1146	Return on Equity
Duke Energy Progress, LLC	06/17	Duke Energy Progress, LLC	Docket No. E-2, Sub 1142	Return on Equity
Public Service Company of North Carolina, Inc.	03/16	Public Service Company of North Carolina, Inc.	Docket No. G-5, Sub 565	Return on Equity
Dominion North Carolina Power	03/16	Dominion North Carolina Power	Docket No. E-22, Sub 532	Return on Equity
Duke Energy Carolinas, LLC	02/13	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1026	Return on Equity
Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	10/12	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	Docket No. E-2, Sub 1023	Return on Equity
Virginia Electric and Power Company d/b/a Dominion North Carolina Power	03/12	Virginia Electric and Power Company d/b/a Dominion North Carolina Power	Docket No. E-22, Sub 479	Return on Equity
Duke Energy Carolinas, LLC	07/11	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 989	Return on Equity

Testimony Listing of:
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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
North Dakota Public Service Commission				
Otter Tail Power Company	11/17	Otter Tail Power Company	Docket No. 17-398	Return on Equity (electric)
Otter Tail Power Company	11/08	Otter Tail Power Company	Docket No. 08-862	Return on Equity (electric)
Oklahoma Corporation Commission				
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/16	CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	Cause No. PUD201600094	Return on Equity
Oklahoma Gas & Electric Company	12/15	Oklahoma Gas & Electric Company	Cause No. PUD201500273	Return on Equity
Public Service Company of Oklahoma	07/15	Public Service Company of Oklahoma	Cause No. PUD201500208	Return on Equity
Oklahoma Gas & Electric Company	07/11	Oklahoma Gas & Electric Company	Cause No. PUD201100087	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/09	CenterPoint Energy Oklahoma Gas	Cause No. PUD200900055	Return on Equity
Pennsylvania Public Utility Commission				
Pike County Light & Power Company	01/14	Pike County Light & Power Company	Docket No. R-2013-2397237	Return on Equity (electric & gas)
Veolia Energy Philadelphia, Inc.	12/13	Veolia Energy Philadelphia, Inc.	Docket No. R-2013-2386293	Return on Equity (steam)
Rhode Island Public Utilities Commission				
The Narragansett Electric Company d/b/a National Grid	02/19	The Narragansett Electric Company d/b/a National Grid	Docket No. 4929	Support for financial remuneration under new power purchase agreement
The Narragansett Electric Company d/b/a National Grid	11/17	The Narragansett Electric Company d/b/a National Grid	Docket No. 4770	Return on Equity (electric & gas)
The Narragansett Electric Company d/b/a National Grid	04/12	The Narragansett Electric Company d/b/a National Grid	Docket No. 4323	Return on Equity (electric & gas)
National Grid RI – Gas	08/08	National Grid RI – Gas	Docket No. 3943	Revenue Decoupling and Return on Equity
South Carolina Public Service Commission				
Duke Energy Carolinas, LLC	11/18	Duke Energy Carolinas, LLC	Docket No. 2018-319-E	Return on Equity
Duke Energy Progress, LLC	11/18	Duke Energy Progress, LLC	Docket No. 2018-318-E	Return on Equity
South Carolina Electric & Gas	08/18	South Carolina Electric & Gas	Docket No. 2017-370-E	Return on Equity
South Carolina Electric & Gas	12/17	South Carolina Electric & Gas	Docket No. 2017-305-E	Return on Equity
Duke Energy Progress, LLC	07/16	Duke Energy Progress, LLC	Docket No. 2016-227-E	Return on Equity

Testimony Listing of:
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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Duke Energy Carolinas, LLC	03/13	Duke Energy Carolinas, LLC	Docket No. 2013-59-E	Return on Equity
South Carolina Electric & Gas	06/12	South Carolina Electric & Gas	Docket No. 2012-218-E	Return on Equity
Duke Energy Carolinas, LLC	08/11	Duke Energy Carolinas, LLC	Docket No. 2011-271-E	Return on Equity
South Carolina Electric & Gas	03/10	South Carolina Electric & Gas	Docket No. 2009-489-E	Return on Equity
South Dakota Public Utilities Commission				
Otter Tail Power Company	04/18	Otter Tail Power Company	Docket No. EL18-021	Return on Equity (electric)
Otter Tail Power Company	08/10	Otter Tail Power Company	Docket No. EL10-011	Return on Equity (electric)
Northern States Power Company	06/09	South Dakota Division of Northern States Power	Docket No. EL09-009	Return on Equity (electric)
Otter Tail Power Company	10/08	Otter Tail Power Company	Docket No. EL08-030	Return on Equity (electric)
Texas Public Utility Commission				
CenterPoint Energy Houston Electric LLC	04/19	CenterPoint Energy Houston Electric LLC	Docket No. 49421	Return on Equity
Texas-New Mexico Power Company	05/18	Texas-New Mexico Power Company	Docket No. 48401	Return on Equity
Entergy Texas, Inc.	05/18	Entergy Texas, Inc.	Docket No. 48371	Return on Equity
Southwestern Public Service Company	08/17	Southwestern Public Service Company	Docket No. 47527	Return on Equity
Oncor Electric Delivery Company, LLC	03/17	Oncor Electric Delivery Company, LLC	Docket No. 46957	Return on Equity
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Return on Equity
Southwestern Electric Power Company	12/16	Southwestern Electric Power Company	Docket No. 46449	Return on Equity (electric)
Sharyland Utilities, L.P.	04/16	Sharyland Utilities, L.P.	Docket No. 45414	Return on Equity
Southwestern Public Service Company	02/16	Southwestern Public Service Company	Docket No. 44524	Return on Equity (electric)
Wind Energy Transmission Texas, LLC	05/15	Wind Energy Transmission Texas, LLC	Docket No. 44746	Return on Equity
Cross Texas Transmission	12/14	Cross Texas Transmission	Docket No. 43950	Return on Equity
Southwestern Public Service Company	12/14	Southwestern Public Service Company	Docket No. 43695	Return on Equity (electric)
Sharyland Utilities, L.P.	05/13	Sharyland Utilities, L.P.	Docket No. 41474	Return on Equity
Wind Energy Texas Transmission, LLC	08/12	Wind Energy Texas Transmission, LLC	Docket No. 40606	Return on Equity
Southwestern Electric Power Company	07/12	Southwestern Electric Power Company	Docket No. 40443	Return on Equity
Oncor Electric Delivery Company, LLC	01/11	Oncor Electric Delivery Company, LLC	Docket No. 38929	Return on Equity
Texas-New Mexico Power Company	08/10	Texas-New Mexico Power Company	Docket No. 38480	Return on Equity (electric)
CenterPoint Energy Houston Electric LLC	06/10	CenterPoint Energy Houston Electric LLC	Docket No. 38339	Return on Equity

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MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Xcel Energy, Inc.	05/10	Southwestern Public Service Company	Docket No. 38147	Return on Equity (electric)
Texas-New Mexico Power Company	08/08	Texas-New Mexico Power Company	Docket No. 36025	Return on Equity (electric)
Xcel Energy, Inc.	05/06	Southwestern Public Service Company	Docket No. 32766	Return on Equity (electric)
Texas Railroad Commission				
Atmos Energy Corporation – Mid-Tex Division	10/18	Atmos Energy Corporation – Mid-Tex Division	GUD 10779	Return on Equity
Atmos Energy Corporation – West Texas Division	06/18	Atmos Energy Corporation – West Texas Division	GUD 10743	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/18	Atmos Energy Corporation – Mid-Texas Division	GUD 10742	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	11/17	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10669	Return on Equity
Atmos Pipeline - Texas	01/17	Atmos Pipeline - Texas	GUD 10580	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	12/16	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10567	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	03/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10432	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/12	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10182	Return on Equity
Atmos Energy Corporation – West Texas Division	06/12	Atmos Energy Corporation – West Texas Division	GUD 10174	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/12	Atmos Energy Corporation – Mid-Texas Division	GUD 10170	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	12/10	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10038	Return on Equity
Atmos Pipeline – Texas	09/10	Atmos Pipeline - Texas	GUD 10000	Return on Equity

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Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/09	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 9902	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	03/08	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	GUD 9791	Return on Equity
Utah Public Service Commission				
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity
Vermont Public Service Board				
Central Vermont Public Service Corporation; Green Mountain Power	02/12	Central Vermont Public Service Corporation; Green Mountain Power	Docket No. 7770	Merger Policy
Central Vermont Public Service Corporation	12/10	Central Vermont Public Service Corporation	Docket No. 7627	Return on Equity (electric)
Green Mountain Power	04/06	Green Mountain Power	Docket Nos. 7175 and 7176	Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket Nos. 7109 and 7160	Return on Equity (gas)
Virginia State Corporation Commission				
Virginia Electric and Power Company	03/19	Virginia Electric and Power Company	Case No. PUR-2019-00050	Return on Equity
Virginia Electric and Power Company	03/17	Virginia Electric and Power Company	Case No. PUR-2017-00038	Return on Equity
Virginia Natural Gas, Inc.	03/17	Virginia Natural Gas, Inc.	Case No. PUE-2016-00143	Return on Equity
Virginia Electric and Power Company	10/16	Virginia Electric and Power Company	Case No. PUE-2016-00112; PUE-2016-00113; PUE-2016-00136	Return on Equity
Washington Gas Light Company	06/16	Washington Gas Light Company	Case No. PUE-2016-00001	Return on Equity
Virginia Electric and Power Company	06/16	Virginia Electric and Power Company	Case Nos. PUE-2016-00063; PUE-2016-00062; PUE-2016-00061; PUE-2016-00060; PUE-2016-00059	Return on Equity
Virginia Electric and Power Company	12/15	Virginia Electric and Power Company	Case Nos. PUE-2015-00058; PUE-2015-00059; PUE-2015-00060; PUE-2015-00061; PUE-2015-00075; PUE-2015-00089; PUE-2015-00102; PUE-2015-00104	Return on Equity
Virginia Electric and Power Company	03/15	Virginia Electric and Power Company	Case No. PUE-2015-00027	Return on Equity
Virginia Electric and Power Company	03/13	Virginia Electric and Power Company	Case No. PUE-2013-00020	Return on Equity

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MANAGEMENT CONSULTANTS

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Virginia Natural Gas, Inc.	02/11	Virginia Natural Gas, Inc.	Case No. PUE-2010-00142	Capital Structure
Columbia Gas of Virginia, Inc.	06/06	Columbia Gas of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies
Dominion Resources	10/01	Virginia Electric and Power Company	Case No. PUE000584	Corporate Structure and Electric Generation Strategy

Expert Reports

United States District Court, District of South Carolina, Columbia Division				
South Carolina Electric & Gas Company	07/18	South Carolina Electric & Gas Company	Case No. 3:18-CV-01795-JMC	Return on Equity
United States District Court, Western District of Texas, Austin Division				
Southwestern Public Service Company	02/12	Southwestern Public Service Company	C.A. No. A-09-CA-917-SS	PURPA and FERC regulations
American Arbitration Association				
Confidential Client	11/14	Confidential Client	Confidential	Economic harm related to failure to perform

Constant Growth Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Retention Growth Estimate	[9] Average Earnings Growth	[10] Low ROE	[11] Mean ROE	[12] High ROE
Atmos Energy Corporation	ATO	$2.10	$98.52	2.13%	2.21%	6.50%	6.40%	7.50%	10.09%	7.62%	8.60%	9.84%	12.33%
Chesapeake Utilities Corporation	CPK	$1.48	$90.47	1.64%	1.70%	6.00%	6.00%	9.00%	10.63%	7.91%	7.69%	9.61%	12.36%
New Jersey Resources Corporation	NJR	$1.17	$48.00	2.44%	2.50%	7.00%	6.00%	2.50%	5.48%	5.25%	4.97%	7.75%	9.52%
Northwest Natural Gas Company	NWN	$1.90	$63.54	2.99%	3.14%	4.30%	4.00%	25.50%	6.42%	10.06%	7.05%	13.20%	28.87%
ONE Gas, Inc.	OGS	$2.00	$85.41	2.34%	2.42%	5.90%	5.00%	9.00%	5.27%	6.29%	7.40%	8.71%	11.45%
South Jersey Industries, Inc.	SJI	$1.15	$30.53	3.77%	3.90%	5.90%	5.90%	9.50%	7.05%	7.09%	9.78%	10.99%	13.45%
Spire Inc.	SR	$2.37	$78.49	3.02%	3.09%	3.90%	2.42%	5.50%	5.85%	4.42%	5.48%	7.50%	8.96%
Proxy Group Mean				2.62%	2.71%	5.64%	5.10%	9.79%	7.26%	6.95%	7.28%	9.66%	13.85%
Proxy Group Median				2.44%	2.50%	5.90%	5.90%	9.00%	6.42%	7.09%	7.40%	9.61%	12.33%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of March 15, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Source: Exhibit (RBH)-2, Value Line
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Constant Growth Discounted Cash Flow Model
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Retention Growth Estimate	[9] Average Earnings Growth	[10] Low ROE	[11] Mean ROE	[12] High ROE
Atmos Energy Corporation	ATO	$2.10	$96.32	2.18%	2.26%	6.50%	6.40%	7.50%	10.09%	7.62%	8.65%	9.89%	12.38%
Chesapeake Utilities Corporation	CPK	$1.48	$86.68	1.71%	1.77%	6.00%	6.00%	9.00%	10.63%	7.91%	7.76%	9.68%	12.43%
New Jersey Resources Corporation	NJR	$1.17	$47.51	2.46%	2.53%	7.00%	6.00%	2.50%	5.48%	5.25%	4.99%	7.77%	9.55%
Northwest Natural Gas Company	NWN	$1.90	$63.82	2.98%	3.13%	4.30%	4.00%	25.50%	6.42%	10.06%	7.04%	13.18%	28.86%
ONE Gas, Inc.	OGS	$2.00	$82.99	2.41%	2.49%	5.90%	5.00%	9.00%	5.27%	6.29%	7.47%	8.78%	11.52%
South Jersey Industries, Inc.	SJI	$1.15	$30.20	3.81%	3.94%	5.90%	5.90%	9.50%	7.05%	7.09%	9.82%	11.03%	13.49%
Spire Inc.	SR	$2.37	$77.11	3.07%	3.14%	3.90%	2.42%	5.50%	5.85%	4.42%	5.53%	7.56%	9.01%
Proxy Group Mean				2.66%	2.75%	5.64%	5.10%	9.79%	7.26%	6.95%	7.32%	9.70%	13.89%
Proxy Group Median				2.46%	2.53%	5.90%	5.90%	9.00%	6.42%	7.09%	7.47%	9.68%	12.38%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of March 15, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Source: Exhibit (RBH)-2, Value Line
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Constant Growth Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Retention Growth Estimate	[9] Average Earnings Growth	[10] Low ROE	[11] Mean ROE	[12] High ROE
Atmos Energy Corporation	ATO	$2.10	$94.59	2.22%	2.30%	6.50%	6.40%	7.50%	10.09%	7.62%	8.69%	9.93%	12.42%
Chesapeake Utilities Corporation	CPK	$1.48	$85.37	1.73%	1.80%	6.00%	6.00%	9.00%	10.63%	7.91%	7.79%	9.71%	12.46%
New Jersey Resources Corporation	NJR	$1.17	$46.75	2.50%	2.57%	7.00%	6.00%	2.50%	5.48%	5.25%	5.03%	7.81%	9.59%
Northwest Natural Gas Company	NWN	$1.90	$64.92	2.93%	3.07%	4.30%	4.00%	25.50%	6.42%	10.06%	6.99%	13.13%	28.80%
ONE Gas, Inc.	OGS	$2.00	$81.02	2.47%	2.55%	5.90%	5.00%	9.00%	5.27%	6.29%	7.53%	8.84%	11.58%
South Jersey Industries, Inc.	SJI	$1.15	$32.02	3.59%	3.72%	5.90%	5.90%	9.50%	7.05%	7.09%	9.60%	10.81%	13.26%
Spire Inc.	SR	$2.37	$75.42	3.14%	3.21%	3.90%	2.42%	5.50%	5.85%	4.42%	5.60%	7.63%	9.08%
Proxy Group Mean				2.66%	2.75%	5.64%	5.10%	9.79%	7.26%	6.95%	7.32%	9.69%	13.89%
Proxy Group Median				2.50%	2.57%	5.90%	5.90%	9.00%	6.42%	7.09%	7.53%	9.71%	12.42%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of March 15, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Source: Exhibit (RBH)-2, Value Line
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])

Retention Growth Estimate

Company	Ticker	[1] Projected Earnings per share 2022-2024	[2] Projected Dividend Declared per share 2022-24	[3] Retention Ratio (B)	[4] Projected Book Value per Share 2022-24	[5] Return on Book Value (R)	[6] B x R	[7] Projected Common Shares Outstanding 2019	[8] Projected Common Shares Outstanding 2022-24	[9] Common Shares Growth Rate	[10] 2019 High Price	[11] 2019 Low Price	[12] 2019 price midpoint	[13] Projected Book Value per Share 2019	[14] Market/ Book Ratio	[15] "S"	[16] "V"	[17] S x V	[18] BR + SV
Atmos Energy Corporation	ATO	5.60	2.70	51.79%	56.05	9.99%	5.17%	120.00	145.00	4.84%	$ 98.40	$ 89.20	$ 93.80	46.55	2.02	9.76%	50.37%	4.92%	10.09%
Chesapeake Utilities Corporation	CPK	5.00	2.15	57.00%	49.00	10.20%	5.82%	17.50	20.00	3.39%	$ 91.50	$ 77.60	$ 84.55	34.95	2.42	8.21%	58.66%	4.82%	10.63%
New Jersey Resources Corporation	NJR	2.40	1.33	44.58%	21.40	11.21%	5.00%	88.00	89.00	0.28%	$ 48.60	$ 43.90	$ 46.25	17.05	2.71	0.77%	63.14%	0.48%	5.48%
Northwest Natural Gas Company	NWN	3.50	2.20	37.14%	29.40	11.90%	4.42%	30.00	32.00	1.63%	$ 64.50	$ 57.20	$ 60.85	27.30	2.23	3.63%	55.14%	2.00%	6.42%
ONE Gas, Inc.	OGS	4.75	2.65	44.21%	47.90	9.92%	4.38%	53.00	55.00	0.93%	$ 84.70	$ 75.80	$ 80.25	41.05	1.95	1.82%	48.85%	0.89%	5.27%
South Jersey Industries, Inc.	SJI	2.50	1.40	44.00%	20.40	12.25%	5.39%	90.00	98.00	2.15%	$ 31.40	$ 26.60	$ 29.00	16.40	1.77	3.80%	43.45%	1.65%	7.05%
Spire Inc.	SR	5.00	2.67	46.60%	47.80	10.46%	4.87%	52.00	55.00	1.41%	$ 79.50	$ 71.70	$ 75.60	44.70	1.69	2.39%	40.87%	0.98%	5.85%
																		Average:	7.26%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Equals 1 - [2] / [1]
[4] Source: Value Line
[5] Equals [1] / [4]
[6] Equals [3] x [5]
[7] Source: Value Line
[8] Source: Value Line
[9] Equals ([8] / [7]) ^ 0.25 - 1
[10] Source: Value Line
[11] Source: Value Line
[12] Equals Average ([10], [11])
[13] Source: Value Line
[14] Equals [12] / [13]
[15] Equals [9] x [14]
[16] Equals 1 - (1 / [14])
[17] Equals [15] x [16]
[18] Equals [6] + [17]

Ex-Ante Market Risk Premium
Market DCF Method Based - Bloomberg

[1]	[2]	[3]
S&P 500 Est. Required Market Return	Current 30-Year Treasury (30-day average)	Implied Market Risk Premium
13.64%	3.03%	10.61%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization	Weight in Index	Estimated Dividend Yield	Long-Term Growth Est.	DCF Result	Weighted DCF Result
Agilent Technologies Inc	A	25,750.54	N/A	0.83%	N/A	N/A	N/A
American Airlines Group Inc	AAL	14,113.82	0.06%	1.29%	9.54%	10.89%	0.0062%
Advance Auto Parts Inc	AAP	11,097.40	0.04%	0.15%	15.47%	15.64%	0.0070%
Apple Inc	AAPL	877,607.91	3.54%	1.58%	9.40%	11.05%	0.3908%
AbbVie Inc	ABBV	119,983.29	0.48%	5.31%	8.81%	14.36%	0.0694%
AmerisourceBergen Corp	ABC	16,925.19	0.07%	2.00%	8.70%	10.79%	0.0074%
ABIOMED Inc	ABMD	15,023.94	0.06%	0.00%	29.00%	29.00%	0.0176%
Abbott Laboratories	ABT	140,271.72	0.57%	1.53%	11.69%	13.30%	0.0752%
Accenture PLC	ACN	106,224.74	0.43%	1.76%	10.27%	12.12%	0.0519%
Adobe Inc	ADBE	125,746.54	0.51%	0.00%	17.16%	17.16%	0.0869%
Analog Devices Inc	ADI	40,289.90	0.16%	1.90%	11.98%	13.98%	0.0227%
Archer-Daniels-Midland Co	ADM	24,184.63	0.10%	3.29%	1.40%	4.71%	0.0046%
Automatic Data Processing Inc	ADP	67,657.64	0.27%	1.87%	14.00%	16.00%	0.0436%
Alliance Data Systems Corp	ADS	9,137.33	0.04%	1.44%	-1.33%	0.10%	0.0000%
Autodesk Inc	ADSK	33,569.67	0.14%	0.00%	51.81%	51.81%	0.0701%
Ameren Corp	AEE	17,868.42	0.07%	2.67%	6.35%	9.11%	0.0066%
American Electric Power Co Inc	AEP	41,342.43	0.17%	3.21%	6.12%	9.43%	0.0157%
AES Corp/VA	AES	12,128.62	0.05%	3.04%	7.67%	10.82%	0.0053%
Aflac Inc	AFL	37,479.10	0.15%	2.19%	3.43%	5.66%	0.0085%
Allergan PLC	AGN	50,307.94	0.20%	1.98%	5.45%	7.48%	0.0152%
American International Group Inc	AIG	38,292.18	0.15%	3.09%	11.00%	14.26%	0.0220%
Apartment Investment & Management Co	AIV	7,325.82	0.03%	4.09%	8.77%	13.03%	0.0038%
Assurant Inc	AIZ	6,091.25	N/A	2.53%	N/A	N/A	N/A
Arthur J Gallagher & Co	AJG	14,776.34	0.06%	2.14%	10.17%	12.41%	0.0074%
Akamai Technologies Inc	AKAM	11,828.01	0.05%	0.00%	15.40%	15.40%	0.0073%
Albemarle Corp	ALB	9,033.50	0.04%	1.61%	12.19%	13.89%	0.0051%
Align Technology Inc	ALGN	20,183.71	0.08%	0.00%	23.19%	23.19%	0.0189%
Alaska Air Group Inc	ALK	6,889.48	0.03%	2.45%	25.37%	28.13%	0.0078%
Allstate Corp/The	ALL	31,483.38	0.13%	2.04%	9.00%	11.13%	0.0141%
Allegion PLC	ALLE	8,351.06	0.03%	1.20%	10.22%	11.48%	0.0039%
Alexion Pharmaceuticals Inc	ALXN	30,411.95	0.12%	0.00%	15.78%	15.78%	0.0193%
Applied Materials Inc	AMAT	38,345.97	0.15%	2.10%	9.23%	11.42%	0.0177%
Advanced Micro Devices Inc	AMD	23,413.41	0.09%	0.00%	15.67%	15.67%	0.0148%
AMETEK Inc	AME	18,385.79	0.07%	0.71%	8.98%	9.72%	0.0072%
Affiliated Managers Group Inc	AMG	5,691.53	0.02%	1.27%	4.98%	6.28%	0.0014%
Amgen Inc	AMGN	119,004.45	0.48%	2.98%	5.83%	8.89%	0.0426%
Ameriprise Financial Inc	AMP	17,473.72	0.07%	2.94%	11.80%	14.92%	0.0105%
American Tower Corp	AMT	83,361.26	0.34%	1.95%	18.21%	20.34%	0.0683%
Amazon.com Inc	AMZN	841,116.18	3.39%	0.00%	37.60%	37.60%	1.2744%
Arista Networks Inc	ANET	22,473.89	0.09%	0.00%	21.64%	21.64%	0.0196%
ANSYS Inc	ANSS	15,110.76	0.06%	0.00%	10.37%	10.37%	0.0063%
Anthem Inc	ANTM	77,947.75	0.31%	1.02%	12.54%	13.62%	0.0428%
Aon PLC	AON	40,799.91	0.16%	1.01%	10.57%	11.63%	0.0191%
AO Smith Corp	AOS	8,614.72	0.03%	1.68%	9.33%	11.09%	0.0039%
Apache Corp	APA	12,932.72	0.05%	5.13%	-5.19%	-0.19%	-0.0001%
Anadarko Petroleum Corp	APC	22,256.11	0.09%	2.64%	19.98%	22.88%	0.0205%
Air Products & Chemicals Inc	APD	40,598.82	0.16%	2.48%	12.30%	14.93%	0.0244%
Amphenol Corp	APH	28,443.48	0.11%	0.93%	10.85%	11.83%	0.0136%
Aptiv PLC	APTV	21,137.43	0.09%	1.12%	10.66%	11.84%	0.0101%
Alexandria Real Estate Equities Inc	ARE	15,840.60	0.06%	2.83%	4.80%	7.69%	0.0049%
Arconic Inc	ARNC	9,209.03	0.04%	0.53%	14.35%	14.91%	0.0055%
Atmos Energy Corp	ATO	11,866.25	0.05%	2.07%	6.50%	8.64%	0.0041%
Activision Blizzard Inc	ATVI	34,089.91	0.14%	0.82%	6.65%	7.50%	0.0103%
AvalonBay Communities Inc	AVB	27,559.05	0.11%	3.06%	5.61%	8.76%	0.0097%
Broadcom Inc	AVGO	114,985.00	0.46%	3.47%	14.11%	17.82%	0.0826%
Avery Dennison Corp	AVY	9,254.65	0.04%	1.91%	5.75%	7.72%	0.0029%
American Water Works Co Inc	AWK	19,125.34	0.08%	1.86%	8.45%	10.39%	0.0080%
American Express Co	AXP	95,214.64	0.38%	1.42%	12.22%	13.72%	0.0526%
AutoZone Inc	AZO	23,947.56	0.10%	0.00%	13.08%	13.08%	0.0126%
Boeing Co/The	BA	214,123.71	0.86%	2.13%	15.15%	17.44%	0.1505%
Bank of America Corp	BAC	282,421.14	1.14%	2.34%	9.45%	11.90%	0.1354%
Baxter International Inc	BAX	39,434.69	0.16%	1.09%	12.20%	13.36%	0.0212%
BB&T Corp	BBT	38,167.50	0.15%	3.41%	9.85%	13.42%	0.0206%
Best Buy Co Inc	BBY	18,737.54	0.08%	2.84%	10.65%	13.64%	0.0103%
Becton Dickinson and Co	BDX	68,320.57	0.28%	1.25%	12.41%	13.73%	0.0378%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization	Weight in Index	Estimated Dividend Yield	Long-Term Growth Est.	DCF Result	Weighted DCF Result
Franklin Resources Inc	BEN	16,976.89	0.07%	3.10%	10.00%	13.25%	0.0091%
Brown-Forman Corp	BF/B	24,125.50	0.10%	1.29%	9.91%	11.27%	0.0110%
Brighthouse Financial Inc	BHF	4,616.65	0.02%	0.00%	11.14%	11.14%	0.0021%
Baker Hughes a GE Co	BHGE	28,864.14	0.12%	2.28%	40.82%	43.56%	0.0507%
Biogen Inc	BIIB	64,888.33	0.26%	0.00%	5.08%	5.08%	0.0133%
Bank of New York Mellon Corp/The	BK	50,721.19	0.20%	2.27%	7.33%	9.69%	0.0198%
Booking Holdings Inc	BKNG	78,869.95	0.32%	0.00%	12.50%	12.50%	0.0397%
BlackRock Inc	BLK	68,933.83	0.28%	3.06%	8.53%	11.72%	0.0325%
Ball Corp	BLL	19,214.83	0.08%	0.70%	6.50%	7.22%	0.0056%
Bristol-Myers Squibb Co	BMY	81,568.49	0.33%	3.30%	11.02%	14.50%	0.0477%
Broadridge Financial Solutions Inc	BR	11,978.74	0.05%	1.84%	10.00%	11.93%	0.0058%
Berkshire Hathaway Inc	BRK/B	503,471.13	2.03%	0.00%	-1.60%	-1.60%	-0.0325%
Boston Scientific Corp	BSX	55,729.53	0.22%	0.00%	33.46%	33.46%	0.0751%
BorgWarner Inc	BWA	7,849.71	0.03%	1.80%	5.78%	7.63%	0.0024%
Boston Properties Inc	BXP	20,509.55	0.08%	2.93%	6.24%	9.26%	0.0077%
Citigroup Inc	C	152,576.63	0.61%	3.00%	11.23%	14.40%	0.0886%
Conagra Brands Inc	CAG	11,213.47	0.05%	3.64%	8.00%	11.79%	0.0053%
Cardinal Health Inc	CAH	14,981.30	0.06%	3.92%	4.77%	8.78%	0.0053%
Caterpillar Inc	CAT	76,357.26	0.31%	2.64%	13.35%	16.17%	0.0497%
Chubb Ltd	CB	62,500.24	0.25%	2.23%	10.60%	12.95%	0.0326%
Cboe Global Markets Inc	CBOE	10,831.52	0.04%	1.35%	13.46%	14.90%	0.0065%
CBRE Group Inc	CBRE	17,006.67	0.07%	0.00%	8.55%	8.55%	0.0059%
CBS Corp	CBS	17,796.49	0.07%	1.63%	15.05%	16.81%	0.0121%
Crown Castle International Corp	CCI	51,958.51	0.21%	3.66%	16.20%	20.16%	0.0422%
Carnival Corp	CCL	38,926.68	0.16%	3.64%	10.93%	14.77%	0.0232%
Cadence Design Systems Inc	CDNS	17,149.55	0.07%	0.00%	10.35%	10.35%	0.0072%
Celanese Corp	CE	12,941.57	0.05%	2.33%	7.05%	9.46%	0.0049%
Celgene Corp	CELG	62,113.46	0.25%	0.00%	20.70%	20.70%	0.0518%
Cerner Corp	CERN	18,783.74	0.08%	0.00%	13.20%	13.20%	0.0100%
CF Industries Holdings Inc	CF	9,595.44	0.04%	2.80%	19.75%	22.83%	0.0088%
Citizens Financial Group Inc	CFG	16,514.19	0.07%	3.75%	16.69%	20.76%	0.0138%
Church & Dwight Co Inc	CHD	16,573.73	0.07%	1.37%	7.68%	9.11%	0.0061%
CH Robinson Worldwide Inc	CHRW	12,179.98	0.05%	2.28%	9.07%	11.45%	0.0056%
Charter Communications Inc	CHTR	89,394.14	0.36%	0.00%	41.16%	41.16%	0.1483%
Cigna Corp	CI	63,260.82	0.25%	0.02%	11.80%	11.82%	0.0301%
Cincinnati Financial Corp	CINF	13,967.01	N/A	2.72%	N/A	N/A	N/A
Colgate-Palmolive Co	CL	57,904.66	0.23%	2.57%	6.07%	8.72%	0.0203%
Clorox Co/The	CLX	20,592.16	0.08%	2.42%	4.91%	7.39%	0.0061%
Comerica Inc	CMA	12,991.70	0.05%	3.20%	13.20%	16.61%	0.0087%
Comcast Corp	CMCSA	183,165.70	0.74%	2.07%	11.03%	13.21%	0.0975%
CME Group Inc	CME	60,875.41	0.25%	3.31%	12.23%	15.74%	0.0386%
Chipotle Mexican Grill Inc	CMG	17,674.27	0.07%	0.00%	20.31%	20.31%	0.0145%
Cummins Inc	CMI	24,766.71	0.10%	2.94%	6.66%	9.70%	0.0097%
CMS Energy Corp	CMS	15,737.21	0.06%	2.76%	6.61%	9.45%	0.0060%
Centene Corp	CNC	24,439.37	0.10%	0.00%	13.68%	13.68%	0.0135%
CenterPoint Energy Inc	CNP	15,449.37	0.06%	3.80%	6.44%	10.36%	0.0065%
Capital One Financial Corp	COF	39,456.38	0.16%	1.96%	4.77%	6.78%	0.0108%
Cabot Oil & Gas Corp	COG	10,977.91	0.04%	1.09%	27.91%	29.16%	0.0129%
Cooper Cos Inc/The	COO	14,576.73	0.06%	0.02%	5.23%	5.25%	0.0031%
ConocoPhillips	COP	76,674.37	0.31%	1.83%	6.00%	7.89%	0.0244%
Costco Wholesale Corp	COST	102,756.03	0.41%	1.01%	10.09%	11.15%	0.0462%
Coty Inc	COTY	8,181.19	0.03%	4.59%	8.76%	13.56%	0.0045%
Campbell Soup Co	CPB	10,843.26	0.04%	3.92%	1.85%	5.80%	0.0025%
Capri Holdings Ltd	CPRI	6,922.04	0.03%	0.00%	6.73%	6.73%	0.0019%
Copart Inc	CPRT	13,470.99	0.05%	0.00%	20.00%	20.00%	0.0109%
salesforce.com Inc	CRM	124,524.21	0.50%	0.00%	24.13%	24.13%	0.1211%
Cisco Systems Inc	CSCO	234,187.87	0.94%	2.56%	6.84%	9.49%	0.0895%
CSX Corp	CSX	59,386.05	0.24%	1.25%	10.47%	11.79%	0.0282%
Cintas Corp	CTAS	21,489.00	0.09%	0.98%	12.02%	13.05%	0.0113%
CenturyLink Inc	CTL	13,054.58	0.05%	10.02%	2.50%	12.64%	0.0066%
Cognizant Technology Solutions Corp	CTSH	41,481.91	0.17%	1.09%	11.40%	12.55%	0.0210%
Citrix Systems Inc	CTXS	13,288.50	0.05%	0.00%	11.85%	11.85%	0.0063%
CVS Health Corp	CVS	72,117.77	0.29%	3.55%	8.22%	11.92%	0.0346%
Chevron Corp	CVX	238,096.86	0.96%	3.77%	6.93%	10.83%	0.1039%
Concho Resources Inc	CXO	20,771.53	0.08%	0.28%	18.60%	18.90%	0.0158%
Dominion Energy Inc	D	61,585.64	0.25%	4.76%	5.60%	10.49%	0.0260%
Delta Air Lines Inc	DAL	34,755.46	0.14%	2.82%	11.99%	14.98%	0.0210%
Deere & Co	DE	50,369.74	0.20%	1.88%	10.39%	12.37%	0.0251%
Discover Financial Services	DFS	24,024.77	0.10%	2.26%	9.83%	12.20%	0.0118%
Dollar General Corp	DG	29,939.90	0.12%	1.13%	12.85%	14.05%	0.0169%
Quest Diagnostics Inc	DGX	11,875.45	0.05%	2.37%	8.05%	10.51%	0.0050%
DR Horton Inc	DHI	15,220.73	0.06%	1.48%	13.10%	14.68%	0.0090%
Danaher Corp	DHR	91,831.94	0.37%	0.53%	9.01%	9.56%	0.0354%
Walt Disney Co/The	DIS	171,379.70	0.69%	1.55%	3.76%	5.33%	0.0368%
Discovery Inc	DISCA	19,134.48	0.08%	0.00%	12.30%	12.30%	0.0095%
DISH Network Corp	DISH	15,238.99	0.06%	0.00%	-11.00%	-11.00%	-0.0068%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
Digital Realty Trust Inc	DLR	25,166.78	0.10%	3.72%	17.36%	21.41%	0.0217%
Dollar Tree Inc	DLTR	23,763.68	0.10%	0.00%	9.41%	9.41%	0.0090%
Dover Corp	DOV	13,167.08	0.05%	2.19%	10.97%	13.28%	0.0070%
Duke Realty Corp	DRE	10,982.08	0.04%	2.82%	4.50%	7.38%	0.0033%
Darden Restaurants Inc	DRI	13,667.51	0.06%	2.71%	10.31%	13.17%	0.0073%
DTE Energy Co	DTE	22,714.93	0.09%	3.06%	5.53%	8.68%	0.0079%
Duke Energy Corp	DUK	65,902.55	0.27%	4.19%	5.04%	9.34%	0.0248%
DaVita Inc	DVA	8,907.39	0.04%	0.00%	19.15%	19.15%	0.0069%
Devon Energy Corp	DVN	12,991.21	0.05%	1.14%	5.82%	6.99%	0.0037%
DowDuPont Inc	DWDP	124,643.25	0.50%	2.84%	6.17%	9.10%	0.0457%
DXC Technology Co	DXC	17,638.83	0.07%	1.16%	6.70%	7.90%	0.0056%
Electronic Arts Inc	EA	29,653.97	0.12%	0.00%	11.87%	11.87%	0.0142%
eBay Inc	EBAY	33,210.16	0.13%	0.70%	10.67%	11.41%	0.0153%
Ecolab Inc	ECL	50,221.75	0.20%	1.07%	13.43%	14.57%	0.0295%
Consolidated Edison Inc	ED	27,240.19	0.11%	3.49%	3.07%	6.61%	0.0073%
Equifax Inc	EFX	13,400.10	0.05%	1.44%	7.16%	8.65%	0.0047%
Edison International	EIX	20,825.85	0.08%	3.88%	5.51%	9.50%	0.0080%
Estee Lauder Cos Inc/The	EL	58,775.59	0.24%	1.02%	12.04%	13.12%	0.0311%
Eastman Chemical Co	EMN	10,992.09	0.04%	3.02%	6.73%	9.85%	0.0044%
Emerson Electric Co	EMR	41,382.36	0.17%	2.92%	8.95%	12.00%	0.0200%
EOG Resources Inc	EOG	51,537.73	0.21%	0.97%	9.90%	10.92%	0.0227%
Equinix Inc	EQIX	36,966.22	0.15%	2.24%	18.39%	20.83%	0.0310%
Equity Residential	EQR	27,656.25	0.11%	2.99%	6.71%	9.79%	0.0109%
Eversource Energy	ES	22,737.05	0.09%	2.99%	5.76%	8.83%	0.0081%
Essex Property Trust Inc	ESS	19,011.30	0.08%	2.69%	6.59%	9.36%	0.0072%
E*TRADE Financial Corp	ETFC	12,074.22	0.05%	1.02%	12.08%	13.16%	0.0064%
Eaton Corp PLC	ETN	34,183.91	0.14%	3.56%	9.23%	12.95%	0.0178%
Entergy Corp	ETR	17,945.69	0.07%	3.89%	-0.89%	2.99%	0.0022%
Evergy Inc	EVRG	14,684.51	0.06%	3.34%	6.67%	10.12%	0.0060%
Edwards Lifesciences Corp	EW	37,346.00	0.15%	0.00%	14.00%	14.00%	0.0211%
Exelon Corp	EXC	48,487.30	0.20%	2.89%	4.12%	7.07%	0.0138%
Expeditors International of Washington I	EXPD	13,048.60	0.05%	1.25%	7.70%	9.00%	0.0047%
Expedia Group Inc	EXPE	17,892.45	0.07%	1.07%	17.20%	18.37%	0.0132%
Extra Space Storage Inc	EXR	12,701.84	0.05%	3.58%	4.39%	8.05%	0.0041%
Ford Motor Co	F	33,631.65	0.14%	6.81%	-0.70%	6.08%	0.0082%
Diamondback Energy Inc	FANG	16,831.02	0.07%	0.63%	22.91%	23.62%	0.0160%
Fastenal Co	FAST	17,821.94	0.07%	2.73%	14.85%	17.79%	0.0128%
Facebook Inc	FB	473,705.23	1.91%	0.00%	21.88%	21.88%	0.4177%
Fortune Brands Home & Security Inc	FBHS	6,456.83	0.03%	1.83%	9.97%	11.88%	0.0031%
Freeport-McMoRan Inc	FCX	17,895.88	0.07%	1.84%	-12.55%	-10.83%	-0.0078%
FedEx Corp	FDX	46,460.54	0.19%	1.44%	14.25%	15.80%	0.0296%
FirstEnergy Corp	FE	21,858.17	0.09%	3.69%	-0.02%	3.67%	0.0032%
F5 Networks Inc	FFIV	9,135.54	0.04%	0.00%	8.41%	8.41%	0.0031%
Fidelity National Information Services I	FIS	35,159.59	0.14%	1.29%	8.10%	9.44%	0.0134%
Fiserv Inc	FISV	33,803.44	0.14%	0.00%	7.40%	7.40%	0.0101%
Fifth Third Bancorp	FITB	18,368.76	0.07%	3.42%	3.95%	7.44%	0.0055%
Foot Locker Inc	FL	6,658.26	0.03%	2.61%	7.31%	10.01%	0.0027%
FLIR Systems Inc	FLIR	6,799.65	N/A	1.36%	N/A	N/A	N/A
Fluor Corp	FLR	5,268.81	0.02%	2.23%	20.49%	22.94%	0.0049%
Flowserve Corp	FLS	5,799.93	0.02%	1.82%	13.05%	14.99%	0.0035%
FleetCor Technologies Inc	FLT	20,543.34	0.08%	0.00%	16.50%	16.50%	0.0137%
FMC Corp	FMC	10,165.42	0.04%	1.85%	9.87%	11.81%	0.0048%
Twenty-First Century Fox Inc	FOXA	96,347.33	0.39%	0.77%	2.66%	3.44%	0.0133%
First Republic Bank/CA	FRC	17,258.40	0.07%	0.73%	12.39%	13.17%	0.0092%
Federal Realty Investment Trust	FRT	9,866.85	0.04%	3.13%	5.91%	9.13%	0.0036%
TechnipFMC PLC	FTI	10,312.46	0.04%	2.27%	15.43%	17.88%	0.0074%
Fortinet Inc	FTNT	14,206.96	0.06%	0.00%	22.10%	22.10%	0.0127%
Fortive Corp	FTV	27,620.46	0.11%	0.37%	13.89%	14.28%	0.0159%
General Dynamics Corp	GD	48,939.58	0.20%	2.32%	10.09%	12.53%	0.0247%
General Electric Co	GE	86,702.60	0.35%	0.40%	1.60%	2.00%	0.0070%
Gilead Sciences Inc	GILD	83,711.76	0.34%	3.82%	-1.48%	2.31%	0.0078%
General Mills Inc	GIS	28,351.54	0.11%	4.15%	6.33%	10.62%	0.0121%
Corning Inc	GLW	27,158.99	0.11%	2.31%	10.39%	12.82%	0.0140%
General Motors Co	GM	53,658.86	0.22%	4.02%	6.03%	10.17%	0.0220%
Alphabet Inc	GOOGL	825,304.62	3.33%	0.00%	15.22%	15.22%	0.5063%
Genuine Parts Co	GPC	15,623.28	0.06%	2.89%	6.34%	9.32%	0.0059%
Global Payments Inc	GPN	21,170.89	0.09%	0.03%	17.00%	17.03%	0.0145%
Gap Inc/The	GPS	9,646.47	0.04%	3.87%	8.70%	12.74%	0.0050%
Garmin Ltd	GRMN	15,718.35	0.06%	2.70%	7.28%	10.07%	0.0064%
Goldman Sachs Group Inc/The	GS	75,908.54	0.31%	1.71%	6.74%	8.51%	0.0260%
WW Grainger Inc	GWW	16,524.18	0.07%	1.92%	12.47%	14.51%	0.0097%
Halliburton Co	HAL	24,405.02	0.10%	2.52%	30.08%	32.98%	0.0324%
Hasbro Inc	HAS	10,913.06	0.04%	3.14%	10.85%	14.16%	0.0062%
Huntington Bancshares Inc/OH	HBAN	14,450.63	0.06%	4.31%	8.20%	12.69%	0.0074%
Hanesbrands Inc	HBI	6,372.73	0.03%	3.55%	3.72%	7.33%	0.0019%
HCA Healthcare Inc	HCA	45,349.26	0.18%	1.03%	11.56%	12.64%	0.0231%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization	Weight in Index	Estimated Dividend Yield	Long-Term Growth Est.	DCF Result	Weighted DCF Result
HCP Inc	HCP	14,877.89	0.06%	4.76%	2.57%	7.40%	0.0044%
Home Depot Inc/The	HD	205,833.84	0.83%	2.94%	10.72%	13.82%	0.1146%
Hess Corp	HES	17,651.75	0.07%	1.74%	-9.23%	-7.57%	-0.0054%
HollyFrontier Corp	HFC	8,913.96	0.04%	2.60%	7.07%	9.76%	0.0035%
Hartford Financial Services Group Inc/Th	HIG	17,549.34	0.07%	2.54%	9.50%	12.16%	0.0086%
Huntington Ingalls Industries Inc	HII	8,489.13	0.03%	1.65%	40.00%	41.98%	0.0144%
Hilton Worldwide Holdings Inc	HLT	25,114.59	0.10%	0.76%	13.26%	14.07%	0.0142%
Harley-Davidson Inc	HOG	5,839.31	0.02%	4.25%	8.60%	13.03%	0.0031%
Hologic Inc	HOLX	12,741.79	0.05%	0.00%	3.10%	3.10%	0.0016%
Honeywell International Inc	HON	113,152.26	0.46%	2.14%	7.88%	10.10%	0.0461%
Helmerich & Payne Inc	HP	5,968.06	0.02%	5.22%	96.36%	104.09%	0.0250%
Hewlett Packard Enterprise Co	HPE	22,021.98	0.09%	2.86%	6.09%	9.03%	0.0080%
HP Inc	HPQ	30,578.03	0.12%	3.18%	3.08%	6.31%	0.0078%
H&R Block Inc	HRB	4,950.19	0.02%	4.12%	10.00%	14.33%	0.0029%
Hormel Foods Corp	HRL	22,798.36	0.09%	1.96%	5.80%	7.82%	0.0072%
Harris Corp	HRS	18,953.95	0.08%	1.68%	7.00%	8.74%	0.0067%
Henry Schein Inc	HSIC	8,976.73	0.04%	0.00%	7.11%	7.11%	0.0026%
Host Hotels & Resorts Inc	HST	14,187.47	0.06%	4.41%	2.70%	7.17%	0.0041%
Hershey Co/The	HSY	23,101.91	0.09%	2.66%	7.20%	9.96%	0.0093%
Humana Inc	HUM	37,997.56	0.15%	0.70%	14.11%	14.86%	0.0228%
International Business Machines Corp	IBM	124,074.05	0.50%	4.67%	0.72%	5.41%	0.0270%
Intercontinental Exchange Inc	ICE	42,427.01	0.17%	1.44%	10.09%	11.60%	0.0198%
IDEXX Laboratories Inc	IDXX	18,595.47	0.07%	0.00%	16.24%	16.24%	0.0122%
International Flavors & Fragrances Inc	IFF	13,285.44	0.05%	2.28%	4.00%	6.32%	0.0034%
Illumina Inc	ILMN	45,546.48	0.18%	0.00%	27.09%	27.09%	0.0497%
Incyte Corp	INCY	18,151.30	0.07%	0.00%	47.53%	47.53%	0.0348%
IHS Markit Ltd	INFO	21,775.61	0.09%	0.00%	11.21%	11.21%	0.0098%
Intel Corp	INTC	244,322.01	0.98%	2.32%	8.54%	10.96%	0.1079%
Intuit Inc	INTU	66,874.51	0.27%	0.70%	16.03%	16.79%	0.0452%
International Paper Co	IP	18,214.75	0.07%	4.43%	6.08%	10.64%	0.0078%
Interpublic Group of Cos Inc/The	IPG	8,598.95	0.03%	4.22%	11.49%	15.95%	0.0055%
IPG Photonics Corp	IPGP	8,135.49	0.03%	0.00%	7.89%	7.89%	0.0026%
IQVIA Holdings Inc	IQV	27,824.78	0.11%	0.00%	16.28%	16.28%	0.0182%
Ingersoll-Rand PLC	IR	25,694.09	0.10%	2.05%	9.92%	12.07%	0.0125%
Iron Mountain Inc	IRM	10,002.75	0.04%	7.07%	5.62%	12.89%	0.0052%
Intuitive Surgical Inc	ISRG	64,395.86	0.26%	0.00%	12.82%	12.82%	0.0333%
Gartner Inc	IT	13,011.79	0.05%	0.00%	14.02%	14.02%	0.0074%
Illinois Tool Works Inc	ITW	46,978.56	0.19%	2.80%	7.27%	10.17%	0.0193%
Invesco Ltd	IVZ	7,852.29	0.03%	6.29%	6.34%	12.83%	0.0041%
JB Hunt Transport Services Inc	JBHT	11,232.72	0.05%	0.98%	18.78%	19.85%	0.0090%
Johnson Controls International plc	JCI	32,702.51	0.13%	3.03%	7.63%	10.77%	0.0142%
Jacobs Engineering Group Inc	JEC	10,297.74	0.04%	0.77%	13.96%	14.78%	0.0061%
Jefferies Financial Group Inc	JEF	5,873.52	N/A	2.57%	N/A	N/A	N/A
Jack Henry & Associates Inc	JKHY	10,591.72	0.04%	1.14%	11.00%	12.20%	0.0052%
Johnson & Johnson	JNJ	366,397.44	1.48%	2.76%	7.34%	10.20%	0.1506%
Juniper Networks Inc	JNPR	9,338.24	0.04%	2.81%	8.76%	11.69%	0.0044%
JPMorgan Chase & Co	JPM	348,870.46	1.41%	3.18%	6.77%	10.05%	0.1413%
Nordstrom Inc	JWN	7,304.58	0.03%	3.55%	10.55%	14.29%	0.0042%
Kellogg Co	K	18,653.63	0.08%	4.34%	3.05%	7.46%	0.0056%
KeyCorp	KEY	17,532.73	0.07%	4.26%	13.17%	17.72%	0.0125%
Keysight Technologies Inc	KEYS	16,163.27	0.07%	0.00%	17.00%	17.00%	0.0111%
Kraft Heinz Co/The	KHC	39,131.66	0.16%	4.99%	2.44%	7.48%	0.0118%
Kimco Realty Corp	KIM	7,441.68	0.03%	6.39%	3.26%	9.75%	0.0029%
KLA-Tencor Corp	KLAC	19,577.49	0.08%	2.51%	8.58%	11.20%	0.0088%
Kimberly-Clark Corp	KMB	41,358.51	0.17%	3.42%	6.09%	9.60%	0.0160%
Kinder Morgan Inc/DE	KMI	44,978.85	0.18%	5.01%	10.00%	15.26%	0.0277%
CarMax Inc	KMX	10,385.52	0.04%	0.00%	12.92%	12.92%	0.0054%
Coca-Cola Co/The	KO	193,664.80	0.78%	3.62%	6.72%	10.46%	0.0816%
Kroger Co/The	KR	19,433.02	0.08%	2.40%	6.75%	9.22%	0.0072%
Kohl's Corp	KSS	11,225.49	0.05%	3.94%	10.40%	14.55%	0.0066%
Kansas City Southern	KSU	11,517.26	0.05%	1.33%	8.97%	10.36%	0.0048%
Loews Corp	L	14,873.88	N/A	0.59%	N/A	N/A	N/A
L Brands Inc	LB	7,312.82	0.03%	4.52%	10.72%	15.48%	0.0046%
Leggett & Platt Inc	LEG	5,636.08	0.02%	3.58%	10.00%	13.76%	0.0031%
Lennar Corp	LEN	15,088.35	0.06%	0.34%	12.74%	13.10%	0.0080%
Laboratory Corp of America Holdings	LH	15,219.90	0.06%	0.00%	7.08%	7.08%	0.0043%
Linde PLC	LIN	97,283.68	N/A	1.77%	N/A	N/A	N/A
LKQ Corp	LKQ	8,762.89	0.04%	0.00%	13.05%	13.05%	0.0046%
L3 Technologies Inc	LLL	16,423.75	0.07%	1.65%	5.00%	6.69%	0.0044%
Eli Lilly & Co	LLY	128,329.78	0.52%	2.03%	13.81%	15.98%	0.0826%
Lockheed Martin Corp	LMT	83,680.89	0.34%	3.02%	7.61%	10.74%	0.0362%
Lincoln National Corp	LNC	12,813.31	0.05%	2.38%	9.00%	11.49%	0.0059%
Alliant Energy Corp	LNT	11,189.93	0.05%	3.00%	6.29%	9.38%	0.0042%
Lowe's Cos Inc	LOW	80,408.11	0.32%	2.08%	15.80%	18.04%	0.0584%
Lam Research Corp	LRCX	27,831.52	0.11%	2.23%	-0.42%	1.81%	0.0020%
Southwest Airlines Co	LUV	28,391.63	0.11%	1.35%	9.97%	11.39%	0.0130%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
Lamb Weston Holdings Inc	LW	10,182.66	0.04%	1.13%	11.02%	12.21%	0.0050%
LyondellBasell Industries NV	LYB	32,290.66	0.13%	4.67%	6.80%	11.63%	0.0151%
Macy's Inc	M	7,290.83	0.03%	6.36%	1.67%	8.08%	0.0024%
Mastercard Inc	MA	237,159.39	0.96%	0.50%	19.66%	20.21%	0.1931%
Mid-America Apartment Communities Inc	MAA	12,262.36	0.05%	3.58%	7.00%	10.70%	0.0053%
Macerich Co/The	MAC	6,017.71	0.02%	7.10%	-0.09%	7.01%	0.0017%
Marriott International Inc/MD	MAR	41,548.29	0.17%	1.38%	10.81%	12.27%	0.0205%
Masco Corp	MAS	11,479.32	0.05%	1.22%	12.50%	13.79%	0.0064%
Mattel Inc	MAT	4,997.88	0.02%	0.00%	10.00%	10.00%	0.0020%
McDonald's Corp	MCD	141,836.26	0.57%	2.53%	8.52%	11.16%	0.0638%
Microchip Technology Inc	MCHP	20,403.03	0.08%	1.69%	12.39%	14.19%	0.0117%
McKesson Corp	MCK	22,877.08	0.09%	1.24%	8.08%	9.37%	0.0086%
Moody's Corp	MCO	33,360.82	0.13%	1.11%	8.00%	9.16%	0.0123%
Mondelez International Inc	MDLZ	69,031.30	0.28%	2.19%	7.33%	9.59%	0.0267%
Medtronic PLC	MDT	125,786.55	0.51%	2.12%	7.70%	9.90%	0.0502%
MetLife Inc	MET	43,373.94	0.17%	3.86%	9.27%	13.31%	0.0233%
MGM Resorts International	MGM	13,970.57	0.06%	1.96%	12.99%	15.08%	0.0085%
Mohawk Industries Inc	MHK	9,296.88	0.04%	0.00%	7.59%	7.59%	0.0028%
McCormick & Co Inc/MD	MKC	18,473.95	0.07%	1.63%	6.10%	7.78%	0.0058%
Martin Marietta Materials Inc	MLM	12,080.31	0.05%	1.01%	13.29%	14.37%	0.0070%
Marsh & McLennan Cos Inc	MMC	47,121.62	0.19%	1.87%	12.27%	14.26%	0.0271%
3M Co	MMM	119,812.46	0.48%	2.76%	7.70%	10.56%	0.0510%
Monster Beverage Corp	MNST	32,735.54	0.13%	0.00%	15.40%	15.40%	0.0203%
Altria Group Inc	MO	106,373.95	0.43%	5.79%	5.57%	11.51%	0.0493%
Mosaic Co/The	MOS	11,066.86	0.04%	0.67%	8.40%	9.10%	0.0041%
Marathon Petroleum Corp	MPC	40,661.76	0.16%	3.55%	16.14%	19.98%	0.0327%
Merck & Co Inc	MRK	210,550.14	0.85%	2.70%	8.76%	11.58%	0.0982%
Marathon Oil Corp	MRO	14,135.57	0.06%	1.16%	0.45%	1.61%	0.0009%
Morgan Stanley	MS	74,041.77	0.30%	3.02%	8.99%	12.15%	0.0362%
MSCI Inc	MSCI	16,050.88	0.06%	1.22%	9.25%	10.53%	0.0068%
Microsoft Corp	MSFT	889,286.26	3.58%	1.54%	11.68%	13.31%	0.4770%
Motorola Solutions Inc	MSI	23,046.86	0.09%	1.65%	4.10%	5.78%	0.0054%
M&T Bank Corp	MTB	23,887.34	0.10%	2.49%	7.98%	10.57%	0.0102%
Mettler-Toledo International Inc	MTD	17,599.78	0.07%	0.00%	12.67%	12.67%	0.0090%
Micron Technology Inc	MU	44,326.19	0.18%	0.36%	-3.30%	-2.94%	-0.0053%
Maxim Integrated Products Inc	MXIM	14,801.79	0.06%	3.40%	8.93%	12.48%	0.0074%
Mylan NV	MYL	14,493.03	0.06%	0.00%	4.86%	4.86%	0.0028%
Noble Energy Inc	NBL	11,170.80	0.05%	1.91%	16.07%	18.13%	0.0082%
Norwegian Cruise Line Holdings Ltd	NCLH	12,094.78	0.05%	0.37%	12.25%	12.64%	0.0062%
Nasdaq Inc	NDAQ	13,820.57	0.06%	2.23%	9.11%	11.45%	0.0064%
NextEra Energy Inc	NEE	91,444.75	0.37%	2.61%	4.90%	7.57%	0.0279%
Newmont Mining Corp	NEM	17,652.67	0.07%	1.69%	5.55%	7.29%	0.0052%
Netflix Inc	NFLX	157,812.93	0.64%	0.00%	32.07%	32.07%	0.2039%
NiSource Inc	NI	10,388.87	0.04%	2.92%	5.75%	8.75%	0.0037%
NIKE Inc	NKE	136,605.63	0.55%	0.98%	18.34%	19.41%	0.1068%
Nektar Therapeutics	NKTR	6,185.93	N/A	0.00%	N/A	N/A	N/A
Nielsen Holdings PLC	NLSN	9,579.30	N/A	4.78%	N/A	N/A	N/A
Northrop Grumman Corp	NOC	46,034.51	0.19%	1.92%	8.89%	10.90%	0.0202%
National Oilwell Varco Inc	NOV	10,153.32	0.04%	0.78%	77.76%	78.84%	0.0323%
NRG Energy Inc	NRG	11,708.61	0.05%	0.29%	38.22%	38.56%	0.0182%
Norfolk Southern Corp	NSC	48,013.58	0.19%	1.90%	13.78%	15.81%	0.0306%
NetApp Inc	NTAP	16,809.10	0.07%	2.34%	13.23%	15.73%	0.0107%
Northern Trust Corp	NTRS	20,739.84	0.08%	2.59%	10.65%	13.38%	0.0112%
Nucor Corp	NUE	17,873.98	0.07%	2.71%	0.85%	3.57%	0.0026%
NVIDIA Corp	NVDA	102,904.86	0.41%	0.39%	7.86%	8.27%	0.0343%
Newell Brands Inc	NWL	6,578.77	0.03%	5.90%	-5.93%	-0.20%	-0.0001%
News Corp	NWSA	7,413.80	0.03%	1.68%	-9.13%	-7.52%	-0.0022%
Realty Income Corp	O	21,642.12	0.09%	3.83%	4.39%	8.30%	0.0072%
ONEOK Inc	OKE	27,516.22	0.11%	5.37%	12.82%	18.54%	0.0206%
Omnicom Group Inc	OMC	16,881.94	0.07%	3.43%	3.78%	7.27%	0.0049%
Oracle Corp	ORCL	189,997.37	0.77%	1.57%	7.54%	9.17%	0.0702%
O'Reilly Automotive Inc	ORLY	29,000.54	0.12%	0.00%	14.83%	14.83%	0.0173%
Occidental Petroleum Corp	OXY	49,072.81	0.20%	4.79%	-0.50%	4.27%	0.0084%
Paychex Inc	PAYX	28,450.79	0.11%	2.88%	9.25%	12.26%	0.0141%
People's United Financial Inc	PBCT	6,555.43	0.03%	4.11%	2.00%	6.15%	0.0016%
PACCAR Inc	PCAR	23,455.49	0.09%	4.08%	5.90%	10.10%	0.0095%
Public Service Enterprise Group Inc	PEG	30,163.62	0.12%	3.14%	6.73%	9.97%	0.0121%
PepsiCo Inc	PEP	162,419.24	0.65%	3.30%	5.48%	8.87%	0.0580%
Pfizer Inc	PFE	231,954.40	0.93%	3.45%	5.45%	8.99%	0.0841%
Principal Financial Group Inc	PFG	14,519.62	0.06%	4.27%	4.16%	8.52%	0.0050%
Procter & Gamble Co/The	PG	256,261.83	1.03%	2.84%	6.51%	9.44%	0.0974%
Progressive Corp/The	PGR	42,980.60	0.17%	1.92%	9.80%	11.82%	0.0205%
Parker-Hannifin Corp	PH	22,091.72	0.09%	1.77%	9.52%	11.36%	0.0101%
PulteGroup Inc	PHM	7,446.81	0.03%	1.63%	7.17%	8.85%	0.0027%
Packaging Corp of America	PKG	9,088.62	0.04%	3.21%	8.25%	11.59%	0.0042%
PerkinElmer Inc	PKI	10,419.90	0.04%	0.31%	15.95%	16.28%	0.0068%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
Prologis Inc	PLD	45,158.27	0.18%	2.83%	6.87%	9.79%	0.0178%
Philip Morris International Inc	PM	141,233.99	0.57%	5.17%	8.62%	14.01%	0.0798%
PNC Financial Services Group Inc/The	PNC	58,906.12	0.24%	3.15%	7.37%	10.63%	0.0252%
Pentair PLC	PNR	7,303.52	0.03%	1.70%	10.29%	12.08%	0.0036%
Pinnacle West Capital Corp	PNW	10,782.89	0.04%	3.13%	5.18%	8.38%	0.0036%
PPG Industries Inc	PPG	25,978.27	0.10%	1.76%	7.49%	9.32%	0.0098%
PPL Corp	PPL	23,583.38	0.10%	5.08%	2.53%	7.67%	0.0073%
Perrigo Co PLC	PRGO	6,542.29	0.03%	1.55%	1.00%	2.56%	0.0007%
Prudential Financial Inc	PRU	39,255.82	0.16%	4.23%	9.00%	13.42%	0.0212%
Public Storage	PSA	37,974.42	0.15%	3.75%	5.15%	9.00%	0.0138%
Phillips 66	PSX	44,818.04	0.18%	3.49%	5.70%	9.29%	0.0168%
PVH Corp	PVH	8,369.50	0.03%	0.14%	11.03%	11.17%	0.0038%
Quanta Services Inc	PWR	5,297.82	0.02%	0.11%	22.00%	22.12%	0.0047%
Pioneer Natural Resources Co	PXD	22,842.69	0.09%	0.31%	26.85%	27.20%	0.0250%
PayPal Holdings Inc	PYPL	118,177.38	0.48%	0.00%	23.55%	23.55%	0.1121%
QUALCOMM Inc	QCOM	68,503.30	0.28%	4.47%	11.71%	16.43%	0.0454%
Qorvo Inc	QRVO	8,553.45	0.03%	0.00%	11.83%	11.83%	0.0041%
Royal Caribbean Cruises Ltd	RCL	24,512.49	0.10%	2.38%	11.72%	14.24%	0.0141%
Everest Re Group Ltd	RE	8,909.91	0.04%	2.52%	10.00%	12.65%	0.0045%
Regency Centers Corp	REG	10,858.44	0.04%	3.57%	4.67%	8.33%	0.0036%
Regeneron Pharmaceuticals Inc	REGN	45,292.12	0.18%	0.00%	13.88%	13.88%	0.0253%
Regions Financial Corp	RF	16,019.15	0.06%	3.85%	10.88%	14.94%	0.0096%
Robert Half International Inc	RHI	7,850.84	0.03%	1.83%	9.25%	11.16%	0.0035%
Red Hat Inc	RHT	32,131.52	0.13%	0.00%	18.40%	18.40%	0.0238%
Raymond James Financial Inc	RJF	11,549.60	0.05%	1.58%	17.00%	18.71%	0.0087%
Ralph Lauren Corp	RL	9,495.96	0.04%	2.02%	6.84%	8.93%	0.0034%
ResMed Inc	RMD	14,383.02	0.06%	1.49%	12.50%	14.09%	0.0082%
Rockwell Automation Inc	ROK	21,437.82	0.09%	2.17%	8.94%	11.21%	0.0097%
Rollins Inc	ROL	13,251.98	0.05%	1.94%	10.00%	12.04%	0.0064%
Roper Technologies Inc	ROP	33,797.89	0.14%	0.56%	11.33%	11.92%	0.0162%
Ross Stores Inc	ROST	33,315.93	0.13%	1.18%	10.38%	11.61%	0.0156%
Republic Services Inc	RSG	25,288.63	0.10%	1.92%	13.01%	15.06%	0.0153%
Raytheon Co	RTN	50,224.43	0.20%	2.09%	9.37%	11.55%	0.0234%
SBA Communications Corp	SBAC	21,498.90	0.09%	0.00%	25.05%	25.05%	0.0217%
Starbucks Corp	SBUX	87,885.21	0.35%	2.12%	13.22%	15.47%	0.0548%
Charles Schwab Corp/The	SCHW	60,580.01	0.24%	1.36%	19.78%	21.28%	0.0519%
Sealed Air Corp	SEE	7,050.16	0.03%	1.46%	6.04%	7.55%	0.0021%
Sherwin-Williams Co/The	SHW	39,948.12	0.16%	1.01%	10.99%	12.05%	0.0194%
SVB Financial Group	SIVB	12,961.49	0.05%	0.01%	11.00%	11.01%	0.0058%
JM Smucker Co/The	SJM	12,009.36	0.05%	3.14%	3.20%	6.39%	0.0031%
Schlumberger Ltd	SLB	58,751.38	0.24%	4.72%	33.69%	39.20%	0.0928%
SL Green Realty Corp	SLG	7,713.78	0.03%	3.77%	-0.59%	3.17%	0.0010%
Snap-on Inc	SNA	8,653.54	0.03%	2.42%	7.93%	10.45%	0.0036%
Synopsys Inc	SNPS	16,340.11	0.07%	0.00%	14.50%	14.50%	0.0095%
Southern Co/The	SO	53,652.50	0.22%	4.76%	3.38%	8.21%	0.0178%
Simon Property Group Inc	SPG	54,406.46	0.22%	4.71%	5.21%	10.04%	0.0220%
S&P Global Inc	SPGI	50,510.55	0.20%	1.10%	11.05%	12.21%	0.0249%
Sempra Energy	SRE	34,150.78	0.14%	3.12%	10.10%	13.38%	0.0184%
SunTrust Banks Inc	STI	28,279.67	0.11%	3.32%	8.04%	11.49%	0.0131%
State Street Corp	STT	26,544.05	0.11%	2.88%	8.69%	11.70%	0.0125%
Seagate Technology PLC	STX	13,314.54	0.05%	5.28%	3.37%	8.74%	0.0047%
Constellation Brands Inc	STZ	32,419.29	0.13%	1.74%	11.12%	12.95%	0.0169%
Stanley Black & Decker Inc	SWK	19,904.96	0.08%	2.04%	10.50%	12.64%	0.0101%
Skyworks Solutions Inc	SWKS	14,579.66	0.06%	1.85%	8.87%	10.80%	0.0063%
Synchrony Financial	SYF	23,645.51	0.10%	2.70%	1.55%	4.28%	0.0041%
Stryker Corp	SYK	72,311.85	0.29%	1.16%	8.54%	9.76%	0.0284%
Symantec Corp	SYMC	14,714.78	0.06%	1.32%	7.50%	8.87%	0.0053%
Sysco Corp	SYY	34,027.17	0.14%	2.28%	12.83%	15.26%	0.0209%
AT&T Inc	T	223,418.37	0.90%	6.67%	4.92%	11.75%	0.1058%
Molson Coors Brewing Co	TAP	13,172.05	0.05%	3.36%	0.26%	3.63%	0.0019%
TransDigm Group Inc	TDG	23,267.87	0.09%	0.00%	11.07%	11.07%	0.0104%
TE Connectivity Ltd	TEL	28,362.12	0.11%	2.12%	11.18%	13.42%	0.0153%
Teleflex Inc	TFX	13,939.59	0.06%	0.45%	12.45%	12.93%	0.0073%
Target Corp	TGT	39,582.10	0.16%	3.44%	6.44%	9.99%	0.0159%
Tiffany & Co	TIF	11,770.39	0.05%	2.22%	10.53%	12.86%	0.0061%
TJX Cos Inc/The	TJX	63,839.93	0.26%	1.68%	11.57%	13.34%	0.0343%
Torchmark Corp	TMK	9,161.74	0.04%	0.82%	7.53%	8.38%	0.0031%
Thermo Fisher Scientific Inc	TMO	104,973.88	0.42%	0.28%	12.00%	12.30%	0.0520%
Tapestry Inc	TPR	9,337.29	0.04%	4.22%	10.58%	15.02%	0.0057%
TripAdvisor Inc	TRIP	7,126.45	0.03%	0.00%	11.39%	11.39%	0.0033%
T Rowe Price Group Inc	TROW	24,248.16	0.10%	2.93%	5.40%	8.41%	0.0082%
Travelers Cos Inc/The	TRV	35,341.81	0.14%	2.39%	17.72%	20.32%	0.0289%
Tractor Supply Co	TSCO	10,849.69	0.04%	1.49%	11.06%	12.64%	0.0055%
Tyson Foods Inc	TSN	23,822.74	N/A	2.41%	N/A	N/A	N/A
Total System Services Inc	TSS	16,691.98	0.07%	0.56%	12.14%	12.74%	0.0086%
Take-Two Interactive Software Inc	TTWO	10,586.30	0.04%	3.31%	10.30%	13.78%	0.0059%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
Twitter Inc	TWTR	23,940.26	0.10%	0.00%	37.35%	37.35%	0.0360%
Texas Instruments Inc	TXN	103,942.52	0.42%	2.83%	10.48%	13.46%	0.0564%
Textron Inc	TXT	12,108.62	0.05%	0.16%	11.26%	11.42%	0.0056%
Under Armour Inc	UAA	9,379.42	0.04%	0.00%	33.97%	33.97%	0.0128%
United Continental Holdings Inc	UAL	21,788.98	0.09%	0.00%	14.17%	14.17%	0.0124%
UDR Inc	UDR	12,438.33	0.05%	3.02%	5.54%	8.64%	0.0043%
Universal Health Services Inc	UHS	12,186.95	0.05%	0.30%	10.88%	11.19%	0.0055%
Ulta Beauty Inc	ULTA	20,071.82	0.08%	0.00%	21.20%	21.20%	0.0171%
UnitedHealth Group Inc	UNH	241,227.98	0.97%	1.49%	13.99%	15.58%	0.1515%
Unum Group	UNM	7,808.08	0.03%	2.94%	9.00%	12.07%	0.0038%
Union Pacific Corp	UNP	119,274.84	0.48%	2.14%	13.86%	16.14%	0.0776%
United Parcel Service Inc	UPS	94,212.28	0.38%	3.50%	8.93%	12.58%	0.0478%
United Rentals Inc	URI	9,562.07	0.04%	0.00%	17.76%	17.76%	0.0068%
US Bancorp	USB	83,325.51	0.34%	3.04%	6.70%	9.84%	0.0330%
United Technologies Corp	UTX	108,584.88	0.44%	2.37%	9.80%	12.28%	0.0537%
Visa Inc	V	312,066.80	1.26%	0.64%	15.59%	16.28%	0.2048%
Varian Medical Systems Inc	VAR	12,400.21	0.05%	0.00%	16.10%	16.10%	0.0080%
VF Corp	VFC	33,539.43	0.14%	2.13%	-25.52%	-23.67%	-0.0320%
Viacom Inc	VIAB	11,572.10	0.05%	2.88%	4.93%	7.88%	0.0037%
Valero Energy Corp	VLO	35,530.64	0.14%	4.22%	19.17%	23.79%	0.0341%
Vulcan Materials Co	VMC	14,842.84	0.06%	1.09%	15.13%	16.31%	0.0098%
Vornado Realty Trust	VNO	12,821.13	0.05%	3.86%	0.74%	4.61%	0.0024%
Verisk Analytics Inc	VRSK	20,999.53	0.08%	0.66%	9.57%	10.26%	0.0087%
VeriSign Inc	VRSN	21,742.63	0.09%	0.00%	8.80%	8.80%	0.0077%
Vertex Pharmaceuticals Inc	VRTX	48,086.50	0.19%	0.00%	49.41%	49.41%	0.0957%
Ventas Inc	VTR	22,322.55	0.09%	5.12%	2.08%	7.25%	0.0065%
Verizon Communications Inc	VZ	241,270.16	0.97%	4.18%	2.30%	6.52%	0.0634%
Wabtec Corp	WAB	11,549.57	0.05%	0.00%	14.00%	14.00%	0.0065%
Waters Corp	WAT	17,518.39	0.07%	0.00%	11.48%	11.48%	0.0081%
Walgreens Boots Alliance Inc	WBA	59,087.94	0.24%	2.85%	9.43%	12.42%	0.0296%
WellCare Health Plans Inc	WCG	12,002.73	0.05%	0.00%	17.08%	17.08%	0.0083%
Western Digital Corp	WDC	13,989.93	0.06%	4.16%	2.72%	6.93%	0.0039%
WEC Energy Group Inc	WEC	24,883.12	0.10%	2.98%	4.89%	7.95%	0.0080%
Welltower Inc	WELL	30,276.58	0.12%	4.56%	6.73%	11.44%	0.0140%
Wells Fargo & Co	WFC	230,095.28	0.93%	3.59%	11.26%	15.05%	0.1396%
Whirlpool Corp	WHR	8,473.07	0.03%	3.57%	5.75%	9.42%	0.0032%
Willis Towers Watson PLC	WLTW	22,418.54	0.09%	1.45%	13.97%	15.52%	0.0140%
Waste Management Inc	WM	42,789.02	0.17%	2.00%	7.69%	9.76%	0.0168%
Williams Cos Inc/The	WMB	33,374.64	0.13%	5.53%	3.90%	9.54%	0.0128%
Walmart Inc	WMT	285,935.70	1.15%	2.17%	4.07%	6.28%	0.0724%
Westrock Co	WRK	9,589.25	0.04%	4.83%	4.73%	9.67%	0.0037%
Western Union Co/The	WU	7,998.60	0.03%	4.24%	3.89%	8.21%	0.0026%
Weyerhaeuser Co	WY	19,058.76	0.08%	5.30%	8.70%	14.23%	0.0109%
Wynn Resorts Ltd	WYNN	12,463.11	0.05%	2.61%	31.10%	34.12%	0.0171%
Cimarex Energy Co	XEC	7,104.74	0.03%	1.09%	66.37%	67.82%	0.0194%
Xcel Energy Inc	XEL	29,052.94	0.12%	2.85%	5.89%	8.83%	0.0103%
Xilinx Inc	XLNX	31,435.36	0.13%	1.16%	9.33%	10.54%	0.0133%
Exxon Mobil Corp	XOM	339,419.41	1.37%	4.21%	15.81%	20.35%	0.2783%
DENTSPLY SIRONA Inc	XRAY	10,957.78	0.04%	0.71%	8.57%	9.31%	0.0041%
Xerox Corp	XRX	7,261.65	0.03%	3.24%	-0.10%	3.14%	0.0009%
Xylem Inc/NY	XYL	13,778.87	0.06%	1.25%	14.00%	15.34%	0.0085%
Yum! Brands Inc	YUM	30,917.19	0.12%	1.67%	13.12%	14.89%	0.0186%
Zimmer Biomet Holdings Inc	ZBH	25,742.25	0.10%	0.79%	4.74%	5.56%	0.0058%
Zions Bancorp NA	ZION	9,151.61	0.04%	2.67%	6.78%	9.53%	0.0035%
Zoetis Inc	ZTS	46,397.79	0.19%	0.63%	15.36%	16.04%	0.0300%
Total Market Capitalization:		24,817,827.63					13.64%

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Bloomberg Professional
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Bloomberg Professional
[7] Source: Bloomberg Professional
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Ex-Ante Market Risk Premium
Market DCF Method Based - Value Line

[1] S&P 500 Est. Required Market Return	[2] Current 30-Year Treasury (30-day average)	[3] Implied Market Risk Premium
16.75%	3.03%	13.72%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
Agilent Technologies Inc	A	25,036.14	0.11%	0.84%	9.50%	10.38%	0.0118%
American Airlines Group Inc	AAL	14,839.21	0.07%	1.24%	1.00%	2.25%	0.0015%
Advance Auto Parts Inc	AAP	11,235.15	0.05%	0.16%	13.00%	13.17%	0.0067%
Apple Inc	AAPL	815,891.00	3.70%	1.87%	17.50%	19.53%	0.7234%
AbbVie Inc	ABBV	117,685.50	0.53%	5.47%	14.50%	20.37%	0.1088%
AmerisourceBergen Corp	ABC	16,107.54	0.07%	2.10%	8.00%	10.18%	0.0074%
ABIOMED Inc	ABMD	14,302.31	0.06%	0.00%	24.50%	24.50%	0.0159%
Abbott Laboratories	ABT	134,886.40	0.61%	1.67%	10.00%	11.75%	0.0720%
Accenture PLC	ACN	103,264.50	0.47%	1.89%	9.50%	11.48%	0.0538%
Adobe Inc	ADBE	124,578.40	0.57%	0.00%	22.00%	22.00%	0.1244%
Analog Devices Inc	ADI	38,923.42	0.18%	2.04%	10.50%	12.65%	0.0223%
Archer-Daniels-Midland Co	ADM	23,615.20	0.11%	3.32%	9.50%	12.98%	0.0139%
Automatic Data Processing Inc	ADP	65,613.21	0.30%	2.23%	15.00%	17.40%	0.0518%
Alliance Data Systems Corp	ADS	9,043.95	0.04%	1.52%	13.50%	15.12%	0.0062%
Autodesk Inc	ADSK	33,458.00	N/A	0.00%	N/A	N/A	N/A
Ameren Corp	AEE	17,413.29	0.08%	2.75%	6.50%	9.34%	0.0074%
American Electric Power Co Inc	AEP	40,174.80	0.18%	3.39%	4.00%	7.46%	0.0136%
AES Corp/VA	AES	11,702.79	N/A	3.11%	N/A	N/A	N/A
Aflac Inc	AFL	36,729.55	0.17%	2.30%	8.50%	10.90%	0.0182%
Allergan PLC	AGN	48,219.60	0.22%	2.07%	4.50%	6.62%	0.0145%
American International Group Inc	AIG	36,987.13	0.17%	3.06%	52.00%	55.86%	0.0938%
Apartment Investment & Management Co	AIV	7,526.18	0.03%	3.26%	5.50%	8.85%	0.0030%
Assurant Inc	AIZ	6,259.43	0.03%	2.39%	7.50%	9.98%	0.0028%
Arthur J Gallagher & Co	AJG	14,372.69	0.07%	2.20%	17.00%	19.39%	0.0126%
Akamai Technologies Inc	AKAM	11,972.36	0.05%	0.00%	17.50%	17.50%	0.0095%
Albemarle Corp	ALB	8,983.42	0.04%	1.74%	8.50%	10.31%	0.0042%
Align Technology Inc	ALGN	18,773.59	0.09%	0.00%	28.50%	28.50%	0.0243%
Alaska Air Group Inc	ALK	6,902.05	0.03%	2.50%	3.50%	6.04%	0.0019%
Allstate Corp/The	ALL	32,167.80	0.15%	2.15%	11.50%	13.77%	0.0201%
Allegion PLC	ALLE	8,325.22	0.04%	1.23%	10.50%	11.79%	0.0045%
Alexion Pharmaceuticals Inc	ALXN	28,594.73	0.13%	0.00%	24.50%	24.50%	0.0318%
Applied Materials Inc	AMAT	35,668.70	0.16%	2.13%	19.00%	21.33%	0.0345%
Advanced Micro Devices Inc	AMD	22,190.40	N/A	0.00%	N/A	N/A	N/A
AMETEK Inc	AME	18,320.91	0.08%	0.71%	10.50%	11.25%	0.0094%
Affiliated Managers Group Inc	AMG	6,061.77	0.03%	1.54%	6.50%	8.09%	0.0022%
Amgen Inc	AMGN	114,247.20	0.52%	3.22%	7.00%	10.33%	0.0536%
Ameriprise Financial Inc	AMP	17,464.92	0.08%	2.88%	16.00%	19.11%	0.0151%
American Tower Corp	AMT	80,110.86	0.36%	1.96%	9.50%	11.55%	0.0420%
Amazon.com Inc	AMZN	795,089.50	3.61%	0.00%	57.00%	57.00%	2.0570%
Arista Networks Inc	ANET	20,825.81	0.09%	0.00%	19.00%	19.00%	0.0180%
ANSYS Inc	ANSS	15,022.29	0.07%	0.00%	13.00%	13.00%	0.0089%
Anthem Inc	ANTM	75,010.34	0.34%	1.10%	18.00%	19.20%	0.0654%
Aon PLC	AON	39,207.06	0.18%	0.98%	9.50%	10.53%	0.0187%
AO Smith Corp	AOS	8,529.03	0.04%	1.74%	12.50%	14.35%	0.0056%
Apache Corp	APA	12,694.77	N/A	3.01%	N/A	N/A	N/A
Anadarko Petroleum Corp	APC	21,356.23	N/A	2.78%	N/A	N/A	N/A
Air Products & Chemicals Inc	APD	39,456.71	0.18%	2.58%	9.50%	12.20%	0.0219%
Amphenol Corp	APH	28,135.39	0.13%	0.99%	10.00%	11.04%	0.0141%
Aptiv PLC	APTV	21,355.66	0.10%	1.07%	11.00%	12.13%	0.0118%
Alexandria Real Estate Equities Inc	ARE	13,640.47	N/A	2.84%	N/A	N/A	N/A
Arconic Inc	ARNC	8,852.99	N/A	1.31%	N/A	N/A	N/A
Atmos Energy Corp	ATO	11,626.18	0.05%	2.18%	7.50%	9.76%	0.0052%
Activision Blizzard Inc	ATVI	31,603.00	0.14%	0.92%	14.50%	15.49%	0.0222%
AvalonBay Communities Inc	AVB	26,997.38	0.12%	3.12%	5.50%	8.71%	0.0107%
Broadcom Inc	AVGO	109,655.60	0.50%	3.99%	47.50%	52.44%	0.2610%
Avery Dennison Corp	AVY	9,379.13	0.04%	2.04%	11.50%	13.66%	0.0058%
American Water Works Co Inc	AWK	18,357.58	0.08%	1.91%	10.00%	12.01%	0.0100%
American Express Co	AXP	92,112.44	0.42%	1.53%	9.00%	10.60%	0.0443%
AutoZone Inc	AZO	23,716.91	0.11%	0.00%	12.50%	12.50%	0.0135%
Boeing Co/The	BA	239,862.40	1.09%	1.95%	17.50%	19.62%	0.2136%
Bank of America Corp	BAC	281,453.10	1.28%	2.10%	13.00%	15.24%	0.1946%
Baxter International Inc	BAX	39,846.76	0.18%	1.02%	12.50%	13.58%	0.0246%
BB&T Corp	BBT	37,807.54	0.17%	3.27%	10.00%	13.43%	0.0231%
Best Buy Co Inc	BBY	18,398.08	0.08%	3.25%	12.00%	15.45%	0.0129%
Becton Dickinson and Co	BDX	66,369.77	0.30%	1.27%	10.00%	11.33%	0.0341%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization	Weight in Index	Estimated Dividend Yield	Long-Term Growth Est.	DCF Result	Weighted DCF Result
Franklin Resources Inc	BEN	15,978.70	0.07%	3.43%	9.00%	12.58%	0.0091%
Brown-Forman Corp	BF/B	23,939.42	0.11%	1.33%	15.50%	16.93%	0.0184%
Brighthouse Financial Inc	BHF	N/A	N/A	0.00%	N/A	N/A	N/A
Baker Hughes a GE Co	BHGE	10,732.60	N/A	2.76%	N/A	N/A	N/A
Biogen Inc	BIIB	63,525.57	0.29%	0.00%	6.50%	6.50%	0.0187%
Bank of New York Mellon Corp/The	BK	50,655.05	0.23%	2.19%	9.00%	11.29%	0.0260%
Booking Holdings Inc	BKNG	80,430.32	0.37%	0.00%	14.00%	14.00%	0.0511%
BlackRock Inc	BLK	67,218.66	0.31%	3.12%	9.00%	12.26%	0.0374%
Ball Corp	BLL	18,331.91	0.08%	0.73%	22.00%	22.81%	0.0190%
Bristol-Myers Squibb Co	BMY	84,074.57	0.38%	3.18%	13.50%	16.89%	0.0645%
Broadridge Financial Solutions Inc	BR	11,410.33	0.05%	2.04%	11.00%	13.15%	0.0068%
Berkshire Hathaway Inc	BRK/B	-	N/A	0.00%	N/A	N/A	N/A
Boston Scientific Corp	BSX	54,780.88	0.25%	0.00%	17.00%	17.00%	0.0423%
BorgWarner Inc	BWA	8,043.50	0.04%	1.76%	8.00%	9.83%	0.0036%
Boston Properties Inc	BXP	20,441.89	0.09%	2.94%	3.50%	6.49%	0.0060%
Citigroup Inc	C	151,168.30	0.69%	3.20%	8.50%	11.84%	0.0812%
Conagra Brands Inc	CAG	10,863.81	0.05%	3.80%	4.50%	8.39%	0.0041%
Cardinal Health Inc	CAH	14,155.00	0.06%	4.11%	10.00%	14.32%	0.0092%
Caterpillar Inc	CAT	78,366.20	0.36%	2.59%	17.00%	19.81%	0.0705%
Chubb Ltd	CB	61,178.88	0.28%	2.20%	8.50%	10.79%	0.0300%
Cboe Global Markets Inc	CBOE	10,351.08	0.05%	1.34%	17.00%	18.45%	0.0087%
CBRE Group Inc	CBRE	16,996.28	0.08%	0.00%	10.50%	10.50%	0.0081%
CBS Corp	CBS	18,427.50	0.08%	1.47%	10.50%	12.05%	0.0101%
Crown Castle International Corp	CCI	50,107.10	0.23%	3.81%	10.50%	14.51%	0.0330%
Carnival Corp	CCL	38,766.00	0.18%	3.61%	13.50%	17.35%	0.0305%
Cadence Design Systems Inc	CDNS	16,581.48	0.08%	0.00%	12.50%	12.50%	0.0094%
Celanese Corp	CE	13,763.99	0.06%	2.36%	10.00%	12.48%	0.0078%
Celgene Corp	CELG	59,909.71	0.27%	0.00%	14.50%	14.50%	0.0394%
Cerner Corp	CERN	18,250.42	0.08%	0.00%	7.50%	7.50%	0.0062%
CF Industries Holdings Inc	CF	9,336.28	0.04%	3.23%	48.50%	52.51%	0.0223%
Citizens Financial Group Inc	CFG	16,556.30	0.08%	3.67%	12.50%	16.40%	0.0123%
Church & Dwight Co Inc	CHD	16,203.06	0.07%	1.39%	10.00%	11.46%	0.0084%
CH Robinson Worldwide Inc	CHRW	12,070.86	0.05%	2.29%	9.50%	11.90%	0.0065%
Charter Communications Inc	CHTR	76,626.79	0.35%	0.00%	16.00%	16.00%	0.0556%
Cigna Corp	CI	39,893.30	0.18%	0.02%	15.50%	15.52%	0.0281%
Cincinnati Financial Corp	CINF	13,762.79	0.06%	2.65%	7.00%	9.74%	0.0061%
Colgate-Palmolive Co	CL	56,382.73	0.26%	2.57%	10.50%	13.20%	0.0338%
Clorox Co/The	CLX	20,124.22	0.09%	2.44%	7.50%	10.03%	0.0092%
Comerica Inc	CMA	13,739.92	0.06%	3.24%	15.50%	18.99%	0.0118%
Comcast Corp	CMCSA	173,706.50	0.79%	2.19%	12.00%	14.32%	0.1129%
CME Group Inc	CME	58,626.37	0.27%	1.74%	4.50%	6.28%	0.0167%
Chipotle Mexican Grill Inc	CMG	16,940.06	0.08%	0.00%	16.50%	16.50%	0.0127%
Cummins Inc	CMI	24,763.55	0.11%	2.96%	8.00%	11.08%	0.0125%
CMS Energy Corp	CMS	15,381.54	0.07%	2.87%	7.00%	9.97%	0.0070%
Centene Corp	CNC	23,275.79	0.11%	0.00%	15.50%	15.50%	0.0164%
CenterPoint Energy Inc	CNP	15,050.95	0.07%	3.86%	12.50%	16.60%	0.0113%
Capital One Financial Corp	COF	38,498.84	0.17%	1.97%	10.00%	12.07%	0.0211%
Cabot Oil & Gas Corp	COG	10,902.31	N/A	1.12%	N/A	N/A	N/A
Cooper Cos Inc/The	COO	14,217.63	0.06%	0.02%	14.50%	14.52%	0.0094%
ConocoPhillips	COP	78,226.89	N/A	1.80%	N/A	N/A	N/A
Costco Wholesale Corp	COST	95,505.97	0.43%	1.12%	8.50%	9.67%	0.0419%
Coty Inc	COTY	8,158.03	0.04%	4.60%	9.00%	13.81%	0.0051%
Campbell Soup Co	CPB	10,811.92	N/A	3.90%	N/A	N/A	N/A
Capri Holdings Ltd	CPRI	6,629.59	0.03%	0.00%	7.50%	7.50%	0.0023%
Copart Inc	CPRT	13,209.87	0.06%	0.00%	13.00%	13.00%	0.0078%
salesforce.com Inc	CRM	119,034.00	0.54%	0.00%	65.00%	65.00%	0.3512%
Cisco Systems Inc	CSCO	226,907.00	1.03%	2.73%	8.00%	10.84%	0.1116%
CSX Corp	CSX	60,815.13	0.28%	1.33%	16.50%	17.94%	0.0495%
Cintas Corp	CTAS	21,290.76	0.10%	1.11%	15.50%	16.70%	0.0161%
CenturyLink Inc	CTL	13,085.74	0.06%	8.26%	0.50%	8.78%	0.0052%
Cognizant Technology Solutions Corp	CTSH	41,951.40	0.19%	1.11%	10.00%	11.17%	0.0213%
Citrix Systems Inc	CTXS	13,852.37	0.06%	1.36%	7.50%	8.91%	0.0056%
CVS Health Corp	CVS	53,354.84	0.24%	3.82%	8.00%	11.97%	0.0290%
Chevron Corp	CVX	232,999.80	1.06%	3.90%	25.00%	29.39%	0.3108%
Concho Resources Inc	CXO	20,518.59	0.09%	0.49%	30.00%	30.56%	0.0285%
Dominion Energy Inc	D	49,858.60	0.23%	4.82%	6.50%	11.48%	0.0260%
Delta Air Lines Inc	DAL	33,999.84	0.15%	3.01%	9.50%	12.65%	0.0195%
Deere & Co	DE	50,328.26	0.23%	1.92%	14.00%	16.05%	0.0367%
Discover Financial Services	DFS	23,623.99	0.11%	2.29%	8.00%	10.38%	0.0111%
Dollar General Corp	DG	31,251.65	0.14%	0.98%	13.00%	14.04%	0.0199%
Quest Diagnostics Inc	DGX	11,236.05	0.05%	2.55%	8.50%	11.16%	0.0057%
DR Horton Inc	DHI	15,138.70	0.07%	1.48%	8.00%	9.54%	0.0066%
Danaher Corp	DHR	87,221.57	0.40%	0.51%	10.50%	11.04%	0.0437%
Walt Disney Co/The	DIS	171,015.00	0.78%	1.54%	7.00%	8.59%	0.0667%
Discovery Inc	DISCA	14,877.87	0.07%	0.00%	17.00%	17.00%	0.0115%
DISH Network Corp	DISH	15,051.83	0.07%	0.00%	-2.00%	-2.00%	-0.0014%

		[4]	[5]	[6]	[7]	[8]	[9]
Company	Ticker	Market Capitalization	Weight in Index	Estimated Dividend Yield	Long-Term Growth Est.	DCF Result	Weighted DCF Result
Digital Realty Trust Inc	DLR	23,146.19	0.11%	3.84%	6.50%	10.46%	0.0110%
Dollar Tree Inc	DLTR	24,548.99	0.11%	0.00%	17.50%	17.50%	0.0195%
Dover Corp	DOV	13,195.41	0.06%	2.13%	13.00%	15.27%	0.0091%
Duke Realty Corp	DRE	10,562.54	0.05%	2.97%	7.00%	10.07%	0.0048%
Darden Restaurants Inc	DRI	13,392.08	0.06%	2.97%	12.00%	15.15%	0.0092%
DTE Energy Co	DTE	22,285.81	0.10%	3.18%	5.00%	8.26%	0.0084%
Duke Energy Corp	DUK	63,870.54	0.29%	4.26%	5.50%	9.88%	0.0286%
DaVita Inc	DVA	8,388.83	0.04%	0.00%	9.50%	9.50%	0.0036%
Devon Energy Corp	DVN	13,275.19	0.06%	1.28%	19.00%	20.40%	0.0123%
DowDuPont Inc	DWDP	125,071.10	N/A	3.08%	N/A	N/A	N/A
DXC Technology Co	DXC	17,374.68	0.08%	1.18%	14.00%	15.26%	0.0120%
Electronic Arts Inc	EA	29,907.36	0.14%	0.00%	11.50%	11.50%	0.0156%
eBay Inc	EBAY	34,870.23	0.16%	1.55%	14.50%	16.16%	0.0256%
Ecolab Inc	ECL	48,992.86	0.22%	1.09%	9.00%	10.14%	0.0225%
Consolidated Edison Inc	ED	26,752.14	0.12%	3.59%	3.00%	6.64%	0.0081%
Equifax Inc	EFX	13,110.43	0.06%	1.44%	7.50%	8.99%	0.0054%
Edison International	EIX	20,265.44	0.09%	3.96%	4.50%	8.55%	0.0079%
Estee Lauder Cos Inc/The	EL	56,233.04	0.26%	1.12%	12.50%	13.69%	0.0349%
Eastman Chemical Co	EMN	11,188.08	0.05%	3.10%	9.50%	12.75%	0.0065%
Emerson Electric Co	EMR	41,443.34	0.19%	2.93%	14.00%	17.14%	0.0322%
EOG Resources Inc	EOG	52,967.57	N/A	1.01%	N/A	N/A	N/A
Equinix Inc	EQIX	34,137.01	0.15%	2.44%	25.50%	28.25%	0.0438%
Equity Residential	EQR	27,023.56	0.12%	2.94%	-15.00%	-12.28%	-0.0151%
Eversource Energy	ES	21,988.72	0.10%	3.08%	5.50%	8.66%	0.0086%
Essex Property Trust Inc	ESS	18,646.38	0.08%	2.76%	0.50%	3.27%	0.0028%
E*TRADE Financial Corp	ETFC	12,127.01	0.06%	1.19%	26.00%	27.34%	0.0151%
Eaton Corp PLC	ETN	34,641.66	0.16%	3.55%	9.00%	12.71%	0.0200%
Entergy Corp	ETR	17,417.73	0.08%	3.99%	0.50%	4.50%	0.0036%
Evergy Inc	EVRG	14,142.51	N/A	3.50%	N/A	N/A	N/A
Edwards Lifesciences Corp	EW	35,747.73	0.16%	0.00%	15.00%	15.00%	0.0243%
Exelon Corp	EXC	46,947.85	0.21%	2.99%	7.50%	10.60%	0.0226%
Expeditors International of Washington I	EXPD	12,830.13	0.06%	1.21%	8.50%	9.76%	0.0057%
Expedia Group Inc	EXPE	18,377.94	0.08%	1.04%	20.00%	21.14%	0.0176%
Extra Space Storage Inc	EXR	12,213.86	0.06%	3.67%	5.00%	8.76%	0.0049%
Ford Motor Co	F	33,732.62	0.15%	7.08%	0.50%	7.60%	0.0116%
Diamondback Energy Inc	FANG	9,646.37	N/A	0.77%	N/A	N/A	N/A
Fastenal Co	FAST	17,659.75	0.08%	2.80%	11.50%	14.46%	0.0116%
Facebook Inc	FB	482,697.00	2.19%	0.00%	26.00%	26.00%	0.5696%
Fortune Brands Home & Security Inc	FBHS	6,510.29	0.03%	1.91%	13.50%	15.54%	0.0046%
Freeport-McMoRan Inc	FCX	17,837.19	N/A	1.95%	N/A	N/A	N/A
FedEx Corp	FDX	45,124.06	0.20%	1.71%	7.50%	9.27%	0.0190%
FirstEnergy Corp	FE	20,856.73	0.09%	3.78%	6.50%	10.40%	0.0098%
F5 Networks Inc	FFIV	9,548.62	0.04%	0.00%	12.00%	12.00%	0.0052%
Fidelity National Information Services I	FIS	34,653.20	0.16%	1.33%	15.50%	16.93%	0.0266%
Fiserv Inc	FISV	34,089.01	0.15%	0.00%	13.50%	13.50%	0.0209%
Fifth Third Bancorp	FITB	17,439.38	0.08%	3.53%	7.00%	10.65%	0.0084%
Foot Locker Inc	FL	7,043.85	0.03%	2.45%	8.00%	10.55%	0.0034%
FLIR Systems Inc	FLIR	6,781.22	0.03%	1.36%	13.50%	14.95%	0.0046%
Fluor Corp	FLR	5,079.22	0.02%	2.31%	8.50%	10.91%	0.0025%
Flowserve Corp	FLS	5,624.22	0.03%	1.76%	7.50%	9.33%	0.0024%
FleetCor Technologies Inc	FLT	20,167.42	0.09%	0.00%	14.50%	14.50%	0.0133%
FMC Corp	FMC	10,479.09	0.05%	2.06%	22.50%	24.79%	0.0118%
Twenty-First Century Fox Inc	FOXA	93,942.03	0.43%	0.71%	12.50%	13.25%	0.0565%
First Republic Bank/CA	FRC	16,728.18	0.08%	0.71%	11.50%	12.25%	0.0093%
Federal Realty Investment Trust	FRT	9,674.32	0.04%	3.10%	3.50%	6.65%	0.0029%
TechnipFMC PLC	FTI	N/A	N/A	0.00%	N/A	N/A	N/A
Fortinet Inc	FTNT	14,046.34	0.06%	0.00%	39.50%	39.50%	0.0252%
Fortive Corp	FTV	28,354.79	N/A	0.35%	N/A	N/A	N/A
General Dynamics Corp	GD	48,022.02	0.22%	2.45%	6.00%	8.52%	0.0186%
General Electric Co	GE	82,197.20	N/A	0.42%	N/A	N/A	N/A
Gilead Sciences Inc	GILD	80,913.82	0.37%	4.03%	-6.50%	-2.60%	-0.0096%
General Mills Inc	GIS	27,686.88	0.13%	4.27%	3.00%	7.33%	0.0092%
Corning Inc	GLW	26,768.36	0.12%	2.36%	15.50%	18.04%	0.0219%
General Motors Co	GM	53,256.00	0.24%	4.10%	3.00%	7.16%	0.0173%
Alphabet Inc	GOOGL	N/A	N/A	0.00%	N/A	N/A	N/A
Genuine Parts Co	GPC	15,681.20	0.07%	2.85%	8.50%	11.47%	0.0082%
Global Payments Inc	GPN	20,543.62	0.09%	0.03%	20.00%	20.03%	0.0187%
Gap Inc/The	GPS	10,207.04	0.05%	3.63%	7.00%	10.76%	0.0050%
Garmin Ltd	GRMN	15,727.16	0.07%	2.55%	10.50%	13.18%	0.0094%
Goldman Sachs Group Inc/The	GS	71,852.89	0.33%	1.66%	9.50%	11.24%	0.0367%
WW Grainger Inc	GWW	16,766.46	0.08%	1.83%	9.50%	11.42%	0.0087%
Halliburton Co	HAL	24,466.68	N/A	2.58%	N/A	N/A	N/A
Hasbro Inc	HAS	10,986.28	0.05%	3.14%	8.00%	11.27%	0.0056%
Huntington Bancshares Inc/OH	HBAN	14,532.33	0.07%	4.24%	12.50%	17.01%	0.0112%
Hanesbrands Inc	HBI	6,610.92	0.03%	3.27%	4.00%	7.34%	0.0022%
HCA Healthcare Inc	HCA	43,444.09	0.20%	1.26%	12.00%	13.34%	0.0263%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
HCP Inc	HCP	14,270.85	0.06%	5.00%	35.50%	41.39%	0.0268%
Home Depot Inc/The	HD	206,418.80	0.94%	2.98%	12.50%	15.67%	0.1468%
Hess Corp	HES	16,770.88	N/A	1.77%	N/A	N/A	N/A
HollyFrontier Corp	HFC	8,693.19	0.04%	2.73%	22.50%	25.54%	0.0101%
Hartford Financial Services Group Inc/Th	HIG	17,230.79	0.08%	2.50%	13.00%	15.66%	0.0122%
Huntington Ingalls Industries Inc	HII	8,441.17	0.04%	1.71%	7.00%	8.77%	0.0034%
Hilton Worldwide Holdings Inc	HLT	24,624.09	0.11%	0.72%	9.00%	9.75%	0.0109%
Harley-Davidson Inc	HOG	6,099.72	0.03%	4.00%	9.00%	13.18%	0.0036%
Hologic Inc	HOLX	12,513.44	0.06%	0.00%	18.50%	18.50%	0.0105%
Honeywell International Inc	HON	112,879.10	0.51%	2.15%	9.00%	11.25%	0.0576%
Helmerich & Payne Inc	HP	5,969.14	0.03%	5.21%	56.50%	63.18%	0.0171%
Hewlett Packard Enterprise Co	HPE	21,593.26	0.10%	2.87%	7.50%	10.48%	0.0103%
HP Inc	HPQ	28,970.98	0.13%	3.40%	9.50%	13.06%	0.0172%
H&R Block Inc	HRB	4,965.53	0.02%	4.26%	8.50%	12.94%	0.0029%
Hormel Foods Corp	HRL	23,204.35	0.11%	1.93%	9.00%	11.02%	0.0116%
Harris Corp	HRS	18,988.70	0.09%	1.70%	13.50%	15.31%	0.0132%
Henry Schein Inc	HSIC	8,749.94	0.04%	0.00%	8.50%	8.50%	0.0034%
Host Hotels & Resorts Inc	HST	14,323.76	N/A	4.28%	N/A	N/A	N/A
Hershey Co/The	HSY	23,474.07	0.11%	2.58%	6.50%	9.16%	0.0098%
Humana Inc	HUM	36,826.21	0.17%	0.82%	13.50%	14.38%	0.0240%
International Business Machines Corp	IBM	123,014.30	N/A	4.82%	N/A	N/A	N/A
Intercontinental Exchange Inc	ICE	42,054.15	0.19%	1.49%	12.50%	14.08%	0.0269%
IDEXX Laboratories Inc	IDXX	17,645.87	0.08%	0.00%	15.00%	15.00%	0.0120%
International Flavors & Fragrances Inc	IFF	11,419.68	0.05%	2.43%	8.00%	10.53%	0.0055%
Illumina Inc	ILMN	42,932.82	0.19%	0.00%	15.50%	15.50%	0.0302%
Incyte Corp	INCY	17,648.26	N/A	0.00%	N/A	N/A	N/A
IHS Markit Ltd	INFO	21,020.29	0.10%	0.00%	15.50%	15.50%	0.0148%
Intel Corp	INTC	240,066.40	1.09%	2.40%	12.50%	15.05%	0.1640%
Intuit Inc	INTU	63,593.36	0.29%	0.77%	14.50%	15.33%	0.0442%
International Paper Co	IP	18,371.06	0.08%	4.36%	15.50%	20.20%	0.0168%
Interpublic Group of Cos Inc/The	IPG	8,741.08	0.04%	4.21%	11.50%	15.95%	0.0063%
IPG Photonics Corp	IPGP	7,834.89	0.04%	0.00%	10.50%	10.50%	0.0037%
IQVIA Holdings Inc	IQV	27,239.02	0.12%	0.00%	12.50%	12.50%	0.0155%
Ingersoll-Rand PLC	IR	25,639.12	0.12%	2.03%	13.50%	15.67%	0.0182%
Iron Mountain Inc	IRM	9,980.53	0.05%	7.00%	6.50%	13.73%	0.0062%
Intuitive Surgical Inc	ISRG	60,886.88	0.28%	0.00%	15.00%	15.00%	0.0415%
Gartner Inc	IT	12,878.63	0.06%	0.00%	13.50%	13.50%	0.0079%
Illinois Tool Works Inc	ITW	46,700.85	0.21%	2.84%	10.00%	12.98%	0.0275%
Invesco Ltd	IVZ	7,674.86	0.03%	6.43%	4.00%	10.56%	0.0037%
JB Hunt Transport Services Inc	JBHT	11,125.03	0.05%	1.02%	11.50%	12.58%	0.0064%
Johnson Controls International plc	JCI	32,556.47	0.15%	2.92%	6.00%	9.01%	0.0133%
Jacobs Engineering Group Inc	JEC	10,124.24	0.05%	0.94%	13.00%	14.00%	0.0064%
Jefferies Financial Group Inc	JEF	6,257.12	0.03%	2.65%	20.50%	23.42%	0.0067%
Jack Henry & Associates Inc	JKHY	10,109.40	0.05%	1.22%	11.50%	12.79%	0.0059%
Johnson & Johnson	JNJ	370,919.30	1.68%	2.71%	10.50%	13.35%	0.2248%
Juniper Networks Inc	JNPR	8,989.08	0.04%	2.93%	5.00%	8.00%	0.0033%
JPMorgan Chase & Co	JPM	342,417.60	1.55%	3.15%	9.50%	12.80%	0.1989%
Nordstrom Inc	JWN	7,558.28	0.03%	3.31%	7.00%	10.43%	0.0036%
Kellogg Co	K	18,842.10	0.09%	4.16%	5.50%	9.77%	0.0084%
KeyCorp	KEY	17,272.59	0.08%	4.07%	13.00%	17.33%	0.0136%
Keysight Technologies Inc	KEYS	15,892.58	0.07%	0.00%	16.00%	16.00%	0.0115%
Kraft Heinz Co/The	KHC	38,873.91	0.18%	5.02%	9.50%	14.76%	0.0260%
Kimco Realty Corp	KIM	7,401.98	0.03%	6.56%	-0.50%	6.04%	0.0020%
KLA-Tencor Corp	KLAC	17,350.86	0.08%	2.62%	10.50%	13.26%	0.0104%
Kimberly-Clark Corp	KMB	39,737.10	0.18%	3.58%	10.50%	14.27%	0.0257%
Kinder Morgan Inc/DE	KMI	44,881.38	0.20%	4.03%	34.50%	39.23%	0.0799%
CarMax Inc	KMX	10,259.00	0.05%	0.00%	11.50%	11.50%	0.0054%
Coca-Cola Co/The	KO	192,711.70	0.87%	3.67%	6.50%	10.29%	0.0900%
Kroger Co/The	KR	20,436.78	0.09%	2.42%	5.00%	7.48%	0.0069%
Kohl's Corp	KSS	11,380.05	0.05%	3.89%	11.00%	15.10%	0.0078%
Kansas City Southern	KSU	11,305.51	0.05%	1.29%	12.00%	13.37%	0.0069%
Loews Corp	L	14,745.63	0.07%	0.53%	16.50%	17.07%	0.0114%
L Brands Inc	LB	7,229.75	0.03%	4.56%	-4.50%	-0.04%	0.0000%
Leggett & Platt Inc	LEG	5,780.13	0.03%	3.43%	9.00%	12.58%	0.0033%
Lennar Corp	LEN	15,417.52	0.07%	0.34%	12.00%	12.36%	0.0086%
Laboratory Corp of America Holdings	LH	14,785.13	0.07%	0.00%	8.50%	8.50%	0.0057%
Linde PLC	LIN	-	N/A	2.09%	N/A	N/A	N/A
LKQ Corp	LKQ	8,845.88	0.04%	0.00%	10.50%	10.50%	0.0042%
L3 Technologies Inc	LLL	16,349.42	0.07%	1.64%	7.00%	8.70%	0.0065%
Eli Lilly & Co	LLY	133,834.70	0.61%	2.04%	12.00%	14.16%	0.0860%
Lockheed Martin Corp	LMT	85,145.81	0.39%	2.97%	14.00%	17.18%	0.0664%
Lincoln National Corp	LNC	12,432.01	0.06%	2.52%	10.50%	13.15%	0.0074%
Alliant Energy Corp	LNT	10,903.75	0.05%	3.07%	6.50%	9.67%	0.0048%
Lowe's Cos Inc	LOW	81,172.27	0.37%	2.09%	13.00%	15.23%	0.0561%
Lam Research Corp	LRCX	25,736.12	0.12%	2.63%	13.00%	15.80%	0.0185%
Southwest Airlines Co	LUV	28,972.97	0.13%	1.22%	11.50%	12.79%	0.0168%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
Lamb Weston Holdings Inc	LW	10,329.15	N/A	1.14%	N/A	N/A	N/A
LyondellBasell Industries NV	LYB	33,727.07	0.15%	4.59%	5.50%	10.22%	0.0156%
Macy's Inc	M	7,163.98	0.03%	6.48%	5.00%	11.64%	0.0038%
Mastercard Inc	MA	230,194.40	1.04%	0.59%	16.00%	16.64%	0.1738%
Mid-America Apartment Communities Inc	MAA	11,930.24	0.05%	3.66%	-4.50%	-0.92%	-0.0005%
Macerich Co/The	MAC	5,999.30	0.03%	7.10%	8.00%	15.38%	0.0042%
Marriott International Inc/MD	MAR	41,692.91	0.19%	1.34%	12.50%	13.92%	0.0263%
Masco Corp	MAS	11,453.28	0.05%	1.23%	14.50%	15.82%	0.0082%
Mattel Inc	MAT	5,000.84	0.02%	0.00%	22.00%	22.00%	0.0050%
McDonald's Corp	MCD	139,162.90	0.63%	2.62%	9.50%	12.24%	0.0773%
Microchip Technology Inc	MCHP	20,011.53	0.09%	1.78%	15.00%	16.91%	0.0154%
McKesson Corp	MCK	21,557.76	0.10%	1.39%	9.00%	10.45%	0.0102%
Moody's Corp	MCO	32,450.90	0.15%	1.18%	11.50%	12.75%	0.0188%
Mondelez International Inc	MDLZ	68,206.15	0.31%	2.31%	9.50%	11.92%	0.0369%
Medtronic PLC	MDT	122,101.20	0.55%	2.33%	7.50%	9.92%	0.0550%
MetLife Inc	MET	43,728.06	0.20%	3.93%	7.00%	11.07%	0.0220%
MGM Resorts International	MGM	14,069.73	0.06%	1.97%	31.00%	33.28%	0.0212%
Mohawk Industries Inc	MHK	9,669.16	0.04%	0.00%	4.50%	4.50%	0.0020%
McCormick & Co Inc/MD	MKC	17,857.72	0.08%	1.68%	10.00%	11.76%	0.0095%
Martin Marietta Materials Inc	MLM	12,312.95	0.06%	0.99%	13.00%	14.05%	0.0079%
Marsh & McLennan Cos Inc	MMC	45,237.58	0.21%	1.85%	9.00%	10.93%	0.0224%
3M Co	MMM	116,375.90	0.53%	2.88%	9.00%	12.01%	0.0634%
Monster Beverage Corp	MNST	34,056.31	0.15%	0.00%	15.00%	15.00%	0.0232%
Altria Group Inc	MO	102,585.90	0.47%	5.85%	10.50%	16.66%	0.0776%
Mosaic Co/The	MOS	10,762.32	0.05%	0.72%	12.00%	12.76%	0.0062%
Marathon Petroleum Corp	MPC	26,536.84	0.12%	3.60%	13.50%	17.34%	0.0209%
Merck & Co Inc	MRK	213,895.50	0.97%	2.74%	5.50%	8.32%	0.0807%
Marathon Oil Corp	MRO	14,128.68	N/A	1.31%	N/A	N/A	N/A
Morgan Stanley	MS	71,050.85	0.32%	2.92%	11.00%	14.08%	0.0454%
MSCI Inc	MSCI	16,129.24	0.07%	1.44%	19.50%	21.08%	0.0154%
Microsoft Corp	MSFT	848,126.40	3.85%	1.67%	15.00%	16.80%	0.6465%
Motorola Solutions Inc	MSI	22,806.61	0.10%	1.64%	12.50%	14.24%	0.0147%
M&T Bank Corp	MTB	23,713.35	0.11%	2.39%	13.00%	15.55%	0.0167%
Mettler-Toledo International Inc	MTD	17,042.66	0.08%	0.00%	10.00%	10.00%	0.0077%
Micron Technology Inc	MU	42,369.60	0.19%	0.00%	7.50%	7.50%	0.0144%
Maxim Integrated Products Inc	MXIM	14,317.85	0.06%	3.51%	11.50%	15.21%	0.0099%
Mylan NV	MYL	13,828.74	0.06%	0.00%	14.00%	14.00%	0.0088%
Noble Energy Inc	NBL	10,862.65	N/A	1.94%	N/A	N/A	N/A
Norwegian Cruise Line Holdings Ltd	NCLH	12,113.91	0.05%	0.00%	16.50%	16.50%	0.0091%
Nasdaq Inc	NDAQ	14,094.70	0.06%	2.05%	9.50%	11.65%	0.0075%
NextEra Energy Inc	NEE	89,820.20	0.41%	2.66%	9.00%	11.78%	0.0480%
Newmont Mining Corp	NEM	17,694.97	0.08%	1.69%	5.00%	6.73%	0.0054%
Netflix Inc	NFLX	153,763.60	0.70%	0.00%	47.00%	47.00%	0.3280%
NiSource Inc	NI	9,899.93	0.04%	2.94%	15.00%	18.16%	0.0082%
NIKE Inc	NKE	134,455.00	0.61%	1.03%	16.00%	17.11%	0.1044%
Nektar Therapeutics	NKTR	6,198.90	N/A	0.00%	N/A	N/A	N/A
Nielsen Holdings PLC	NLSN	9,275.71	0.04%	5.36%	5.00%	10.49%	0.0044%
Northrop Grumman Corp	NOC	47,162.60	0.21%	1.74%	9.50%	11.32%	0.0242%
National Oilwell Varco Inc	NOV	10,189.31	0.05%	0.75%	41.50%	42.41%	0.0196%
NRG Energy Inc	NRG	11,956.71	N/A	0.29%	N/A	N/A	N/A
Norfolk Southern Corp	NSC	48,671.13	0.22%	1.93%	13.50%	15.56%	0.0344%
NetApp Inc	NTAP	15,674.62	0.07%	2.52%	20.50%	23.28%	0.0166%
Northern Trust Corp	NTRS	19,921.12	0.09%	2.67%	10.00%	12.80%	0.0116%
Nucor Corp	NUE	18,525.19	0.08%	2.71%	21.50%	24.50%	0.0206%
NVIDIA Corp	NVDA	91,048.61	0.41%	0.43%	23.00%	23.48%	0.0970%
Newell Brands Inc	NWL	7,596.55	0.03%	5.94%	9.50%	15.72%	0.0054%
News Corp	NWSA	7,545.08	N/A	1.55%	N/A	N/A	N/A
Realty Income Corp	O	19,741.51	0.09%	3.90%	4.50%	8.49%	0.0076%
ONEOK Inc	OKE	27,104.44	0.12%	5.46%	18.50%	24.47%	0.0301%
Omnicom Group Inc	OMC	16,686.86	0.08%	3.49%	7.00%	10.61%	0.0080%
Oracle Corp	ORCL	190,970.60	0.87%	1.45%	9.50%	11.02%	0.0955%
O'Reilly Automotive Inc	ORLY	29,199.64	0.13%	0.00%	13.00%	13.00%	0.0172%
Occidental Petroleum Corp	OXY	49,567.18	N/A	4.78%	N/A	N/A	N/A
Paychex Inc	PAYX	27,363.42	0.12%	3.26%	11.00%	14.44%	0.0179%
People's United Financial Inc	PBCT	5,854.36	0.03%	4.15%	11.00%	15.38%	0.0041%
PACCAR Inc	PCAR	23,478.57	0.11%	4.92%	7.00%	12.09%	0.0129%
Public Service Enterprise Group Inc	PEG	29,736.00	0.13%	3.22%	4.50%	7.79%	0.0105%
PepsiCo Inc	PEP	163,933.20	0.74%	3.20%	7.50%	10.82%	0.0805%
Pfizer Inc	PFE	239,253.90	1.09%	3.48%	14.00%	17.72%	0.1925%
Principal Financial Group Inc	PFG	14,180.00	0.06%	4.32%	6.50%	10.96%	0.0071%
Procter & Gamble Co/The	PG	246,530.70	1.12%	2.92%	10.50%	13.57%	0.1519%
Progressive Corp/The	PGR	42,111.48	0.19%	0.55%	20.00%	20.61%	0.0394%
Parker-Hannifin Corp	PH	22,039.91	0.10%	1.78%	14.00%	15.90%	0.0159%
PulteGroup Inc	PHM	7,628.81	0.03%	1.60%	15.50%	17.22%	0.0060%
Packaging Corp of America	PKG	9,226.69	0.04%	3.24%	9.50%	12.89%	0.0054%
PerkinElmer Inc	PKI	10,357.75	0.05%	0.30%	11.50%	11.82%	0.0056%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
Prologis Inc	PLD	36,997.57	0.17%	3.05%	9.00%	12.19%	0.0205%
Philip Morris International Inc	PM	135,196.60	0.61%	5.24%	7.50%	12.94%	0.0794%
PNC Financial Services Group Inc/The	PNC	58,207.38	0.26%	3.02%	9.50%	12.66%	0.0335%
Pentair PLC	PNR	7,247.84	0.03%	1.73%	5.50%	7.28%	0.0024%
Pinnacle West Capital Corp	PNW	10,387.91	0.05%	3.28%	6.00%	9.38%	0.0044%
PPG Industries Inc	PPG	26,348.97	0.12%	1.75%	4.50%	6.29%	0.0075%
PPL Corp	PPL	23,080.84	0.10%	5.24%	3.00%	8.32%	0.0087%
Perrigo Co PLC	PRGO	6,324.14	0.03%	1.81%	0.50%	2.31%	0.0007%
Prudential Financial Inc	PRU	38,652.11	0.18%	4.25%	6.50%	10.89%	0.0191%
Public Storage	PSA	37,234.10	0.17%	4.06%	7.00%	11.20%	0.0189%
Phillips 66	PSX	44,475.50	0.20%	3.61%	12.50%	16.34%	0.0330%
PVH Corp	PVH	8,369.95	0.04%	0.14%	11.00%	11.15%	0.0042%
Quanta Services Inc	PWR	5,203.71	0.02%	0.46%	19.50%	20.00%	0.0047%
Pioneer Natural Resources Co	PXD	23,237.38	0.11%	0.37%	75.00%	75.51%	0.0796%
PayPal Holdings Inc	PYPL	113,335.40	0.51%	0.00%	18.50%	18.50%	0.0952%
QUALCOMM Inc	QCOM	65,376.30	0.30%	5.00%	10.50%	15.76%	0.0468%
Qorvo Inc	QRVO	8,407.12	N/A	0.00%	N/A	N/A	N/A
Royal Caribbean Cruises Ltd	RCL	24,180.85	0.11%	2.42%	11.00%	13.55%	0.0149%
Everest Re Group Ltd	RE	8,866.74	0.04%	2.61%	10.00%	12.74%	0.0051%
Regency Centers Corp	REG	10,932.52	0.05%	3.66%	14.00%	17.92%	0.0089%
Regeneron Pharmaceuticals Inc	REGN	44,646.68	0.20%	0.00%	12.00%	12.00%	0.0243%
Regions Financial Corp	RF	16,907.40	0.08%	3.76%	13.50%	17.51%	0.0134%
Robert Half International Inc	RHI	7,942.78	0.04%	1.90%	9.00%	10.99%	0.0040%
Red Hat Inc	RHT	31,873.36	0.14%	0.00%	17.50%	17.50%	0.0253%
Raymond James Financial Inc	RJF	11,314.04	0.05%	1.74%	12.00%	13.84%	0.0071%
Ralph Lauren Corp	RL	9,695.31	0.04%	2.03%	7.00%	9.10%	0.0040%
ResMed Inc	RMD	14,398.11	0.07%	1.47%	14.50%	16.08%	0.0105%
Rockwell Automation Inc	ROK	20,991.00	0.10%	2.25%	10.50%	12.87%	0.0123%
Rollins Inc	ROL	13,082.90	0.06%	1.05%	13.50%	14.62%	0.0087%
Roper Technologies Inc	ROP	33,020.35	0.15%	0.58%	14.50%	15.12%	0.0227%
Ross Stores Inc	ROST	34,289.47	0.16%	1.10%	11.50%	12.66%	0.0197%
Republic Services Inc	RSG	25,474.61	0.12%	1.98%	12.00%	14.10%	0.0163%
Raytheon Co	RTN	50,822.04	0.23%	1.93%	10.00%	12.03%	0.0277%
SBA Communications Corp	SBAC	21,353.87	0.10%	0.00%	35.50%	35.50%	0.0344%
Starbucks Corp	SBUX	87,789.41	0.40%	2.21%	13.50%	15.86%	0.0632%
Charles Schwab Corp/The	SCHW	59,503.46	0.27%	1.55%	16.00%	17.67%	0.0477%
Sealed Air Corp	SEE	6,983.65	0.03%	1.44%	19.00%	20.58%	0.0065%
Sherwin-Williams Co/The	SHW	38,765.84	0.18%	1.09%	13.00%	14.16%	0.0249%
SVB Financial Group	SIVB	12,737.40	0.06%	0.00%	21.50%	21.50%	0.0124%
JM Smucker Co/The	SJM	11,679.29	0.05%	3.37%	4.50%	7.95%	0.0042%
Schlumberger Ltd	SLB	58,840.23	0.27%	4.71%	26.00%	31.32%	0.0837%
SL Green Realty Corp	SLG	8,495.09	0.04%	3.81%	6.50%	10.43%	0.0040%
Snap-on Inc	SNA	9,016.65	0.04%	2.37%	8.00%	10.46%	0.0043%
Synopsys Inc	SNPS	15,414.24	0.07%	0.00%	10.50%	10.50%	0.0073%
Southern Co/The	SO	50,439.51	0.23%	4.91%	3.50%	8.50%	0.0195%
Simon Property Group Inc	SPG	54,574.18	0.25%	4.85%	3.00%	7.92%	0.0196%
S&P Global Inc	SPGI	49,296.84	0.22%	1.16%	13.00%	14.24%	0.0319%
Sempra Energy	SRE	33,345.80	0.15%	3.25%	9.50%	12.90%	0.0195%
SunTrust Banks Inc	STI	28,471.19	0.13%	3.39%	13.50%	17.12%	0.0221%
State Street Corp	STT	25,949.53	0.12%	2.75%	9.00%	11.87%	0.0140%
Seagate Technology PLC	STX	12,794.64	0.06%	5.58%	9.00%	14.83%	0.0086%
Constellation Brands Inc	STZ	31,828.13	0.14%	1.91%	11.00%	13.02%	0.0188%
Stanley Black & Decker Inc	SWK	19,825.11	0.09%	2.06%	10.00%	12.16%	0.0109%
Skyworks Solutions Inc	SWKS	13,840.95	0.06%	1.91%	11.00%	13.02%	0.0082%
Synchrony Financial	SYF	22,639.37	0.10%	2.67%	11.00%	13.82%	0.0142%
Stryker Corp	SYK	69,995.42	0.32%	1.11%	15.00%	16.19%	0.0514%
Symantec Corp	SYMC	13,987.71	0.06%	1.37%	9.50%	10.94%	0.0069%
Sysco Corp	SYY	33,825.30	0.15%	2.37%	13.00%	15.52%	0.0238%
AT&T Inc	T	217,866.30	0.99%	6.85%	5.50%	12.54%	0.1240%
Molson Coors Brewing Co	TAP	12,956.63	0.06%	2.73%	11.00%	13.88%	0.0082%
TransDigm Group Inc	TDG	22,604.02	0.10%	0.00%	6.50%	6.50%	0.0067%
TE Connectivity Ltd	TEL	28,825.34	0.13%	2.17%	9.50%	11.77%	0.0154%
Teleflex Inc	TFX	13,222.12	0.06%	0.47%	12.00%	12.50%	0.0075%
Target Corp	TGT	39,746.34	0.18%	3.36%	7.00%	10.48%	0.0189%
Tiffany & Co	TIF	11,518.33	0.05%	2.49%	12.00%	14.64%	0.0077%
TJX Cos Inc/The	TJX	63,815.25	0.29%	1.55%	13.00%	14.65%	0.0424%
Torchmark Corp	TMK	9,113.65	0.04%	0.79%	10.00%	10.83%	0.0045%
Thermo Fisher Scientific Inc	TMO	100,970.10	0.46%	0.30%	10.50%	10.82%	0.0496%
Tapestry Inc	TPR	9,912.20	0.04%	3.95%	13.00%	17.21%	0.0077%
TripAdvisor Inc	TRIP	7,025.14	0.03%	0.00%	10.50%	10.50%	0.0033%
T Rowe Price Group Inc	TROW	23,355.01	0.11%	3.16%	11.50%	14.84%	0.0157%
Travelers Cos Inc/The	TRV	34,818.55	0.16%	2.34%	6.50%	8.92%	0.0141%
Tractor Supply Co	TSCO	11,263.13	0.05%	1.48%	10.50%	12.06%	0.0062%
Tyson Foods Inc	TSN	23,464.26	0.11%	2.34%	7.00%	9.42%	0.0100%
Total System Services Inc	TSS	16,968.84	0.08%	0.56%	11.50%	12.09%	0.0093%
Take-Two Interactive Software Inc	TTWO	9,998.64	0.05%	0.00%	29.50%	29.50%	0.0134%

Company	Ticker	[4] Market Capitalization	[5] Weight in Index	[6] Estimated Dividend Yield	[7] Long-Term Growth Est.	[8] DCF Result	[9] Weighted DCF Result
Twitter Inc	TWTR	22,903.34	N/A	0.00%	N/A	N/A	N/A
Texas Instruments Inc	TXN	99,193.49	0.45%	2.94%	12.50%	15.62%	0.0703%
Textron Inc	TXT	12,608.53	0.06%	0.15%	15.00%	15.16%	0.0087%
Under Armour Inc	UAA	9,706.24	0.04%	0.00%	11.50%	11.50%	0.0051%
United Continental Holdings Inc	UAL	22,508.25	0.10%	0.00%	8.50%	8.50%	0.0087%
UDR Inc	UDR	11,960.93	0.05%	2.89%	-2.50%	0.35%	0.0002%
Universal Health Services Inc	UHS	11,982.15	0.05%	0.31%	10.50%	10.83%	0.0059%
Ulta Beauty Inc	ULTA	18,162.36	0.08%	0.00%	20.00%	20.00%	0.0165%
UnitedHealth Group Inc	UNH	227,232.00	1.03%	1.52%	13.50%	15.12%	0.1560%
Unum Group	UNM	7,891.53	0.04%	2.88%	9.50%	12.52%	0.0045%
Union Pacific Corp	UNP	121,646.20	0.55%	2.13%	14.50%	16.78%	0.0927%
United Parcel Service Inc	UPS	91,792.74	0.42%	3.63%	8.50%	12.28%	0.0512%
United Rentals Inc	URI	10,110.32	0.05%	0.00%	17.00%	17.00%	0.0078%
US Bancorp	USB	82,256.33	0.37%	3.04%	7.00%	10.15%	0.0379%
United Technologies Corp	UTX	99,690.48	0.45%	2.36%	9.50%	11.97%	0.0542%
Visa Inc	V	295,275.10	1.34%	0.74%	14.50%	15.29%	0.2050%
Varian Medical Systems Inc	VAR	12,124.13	0.06%	0.00%	9.50%	9.50%	0.0052%
VF Corp	VFC	33,615.12	0.15%	2.40%	12.00%	14.54%	0.0222%
Viacom Inc	VIAB	11,742.30	0.05%	2.75%	4.00%	6.81%	0.0036%
Valero Energy Corp	VLO	34,222.22	0.16%	4.47%	9.00%	13.67%	0.0212%
Vulcan Materials Co	VMC	15,032.73	0.07%	1.09%	18.00%	19.19%	0.0131%
Vornado Realty Trust	VNO	12,861.43	0.06%	3.91%	-5.50%	-1.70%	-0.0010%
Verisk Analytics Inc	VRSK	20,861.78	0.09%	0.79%	9.50%	10.33%	0.0098%
VeriSign Inc	VRSN	21,305.37	0.10%	0.00%	12.00%	12.00%	0.0116%
Vertex Pharmaceuticals Inc	VRTX	45,654.68	N/A	0.00%	N/A	N/A	N/A
Ventas Inc	VTR	21,964.76	0.10%	5.24%	3.50%	8.83%	0.0088%
Verizon Communications Inc	VZ	232,632.50	1.06%	4.30%	4.50%	8.90%	0.0939%
Wabtec Corp	WAB	6,736.41	0.03%	0.69%	10.00%	10.72%	0.0033%
Waters Corp	WAT	18,051.76	0.08%	0.00%	11.00%	11.00%	0.0090%
Walgreens Boots Alliance Inc	WBA	56,408.58	0.26%	2.94%	10.00%	13.09%	0.0335%
WellCare Health Plans Inc	WCG	11,783.78	0.05%	0.00%	23.00%	23.00%	0.0123%
Western Digital Corp	WDC	13,674.09	0.06%	4.26%	1.50%	5.79%	0.0036%
WEC Energy Group Inc	WEC	24,241.63	0.11%	3.12%	6.00%	9.21%	0.0101%
Welltower Inc	WELL	27,916.92	0.13%	4.74%	8.50%	13.44%	0.0170%
Wells Fargo & Co	WFC	234,070.40	1.06%	3.68%	6.00%	9.79%	0.1040%
Whirlpool Corp	WHR	8,797.44	0.04%	3.35%	8.00%	11.48%	0.0046%
Willis Towers Watson PLC	WLTW	22,101.32	N/A	1.53%	N/A	N/A	N/A
Waste Management Inc	WM	42,584.36	0.19%	2.06%	9.00%	11.15%	0.0216%
Williams Cos Inc/The	WMB	32,612.00	0.15%	5.64%	19.00%	25.18%	0.0373%
Walmart Inc	WMT	283,117.60	1.29%	2.18%	7.00%	9.26%	0.1189%
Westrock Co	WRK	9,547.03	0.04%	4.87%	14.50%	19.72%	0.0085%
Western Union Co/The	WU	7,857.93	0.04%	4.52%	7.00%	11.68%	0.0042%
Weyerhaeuser Co	WY	18,174.62	0.08%	5.59%	17.50%	23.58%	0.0195%
Wynn Resorts Ltd	WYNN	12,903.11	0.06%	2.53%	20.00%	22.78%	0.0133%
Cimarex Energy Co	XEC	6,825.10	0.03%	1.12%	32.50%	33.80%	0.0105%
Xcel Energy Inc	XEL	28,498.36	0.13%	2.92%	5.50%	8.50%	0.0110%
Xilinx Inc	XLNX	30,356.90	0.14%	1.20%	11.00%	12.27%	0.0169%
Exxon Mobil Corp	XOM	339,397.50	1.54%	4.19%	14.00%	18.48%	0.2847%
DENTSPLY SIRONA Inc	XRAY	10,728.95	0.05%	0.73%	3.00%	3.74%	0.0018%
Xerox Corp	XRX	7,413.70	0.03%	3.31%	2.50%	5.85%	0.0020%
Xylem Inc/NY	XYL	13,535.00	0.06%	1.28%	15.50%	16.88%	0.0104%
Yum! Brands Inc	YUM	30,217.02	0.14%	1.74%	10.00%	11.83%	0.0162%
Zimmer Biomet Holdings Inc	ZBH	24,763.56	0.11%	0.79%	4.50%	5.31%	0.0060%
Zions Bancorp NA	ZION	9,360.55	0.04%	2.46%	15.00%	17.64%	0.0075%
Zoetis Inc	ZTS	44,514.70	0.20%	0.71%	13.50%	14.26%	0.0288%
Total Market Capitalization:		22,031,879.85					16.75%

Notes:
[1] Equals sum of Col. [9]
[2] Source: Bloomberg Professional
[3] Equals [1] − [2]
[4] Source: Value Line
[5] Equals weight in S&P 500 based on market capitalization
[6] Source: Value Line
[7] Source: Value Line
[8] Equals ([6] x (1 + (0.5 x [7]))) + [7]
[9] Equals Col. [5] x Col. [8]

Bloomberg, Value Line, and Calculated Beta Coefficients

Company	Ticker	[1] Bloomberg	[2] Value Line
Atmos Energy Corporation	ATO	0.496	0.600
Chesapeake Utilities Corporation	CPK	0.617	0.700
New Jersey Resources Corporation	NJR	0.618	0.700
Northwest Natural Gas Company	NWN	0.589	0.650
ONE Gas, Inc.	OGS	0.521	0.650
South Jersey Industries, Inc.	SJI	0.719	0.850
Spire Inc.	SR	0.457	0.650
Mean		0.574	0.686

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line

Capital Asset Pricing Model Results
Bloomberg, and Value Line Derived Market Risk Premium

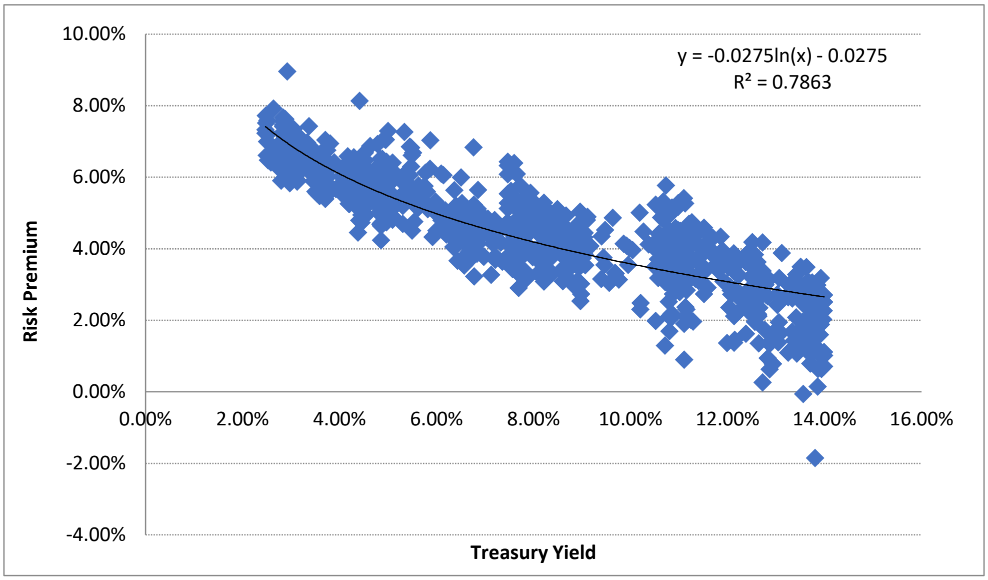
	[1]	[2]	[3]	[4]	[5]	[6]
			Ex-Ante Market Risk Premium		CAPM Result	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP AVERAGE BLOOMBERG BETA COEFFICIENT						
Current 30-Year Treasury [7]	3.03%	0.574	10.61%	13.72%	9.12%	10.90%
Projected 30-Year Treasury [8]	3.25%	0.574	10.61%	13.72%	9.34%	11.12%
Long-Term Projected 30-Year Treasury [9]	4.05%	0.574	10.61%	13.72%	10.14%	11.92%
Mean					9.53%	11.32%

			Ex-Ante Market Risk Premium		CAPM Result	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP AVERAGE VALUE LINE AVERAGE BETA COEFFICIENT						
Current 30-Year Treasury [7]	3.03%	0.686	10.61%	13.72%	10.31%	12.44%
Projected 30-Year Treasury [8]	3.25%	0.686	10.61%	13.72%	10.52%	12.66%
Long-Term Projected 30-Year Treasury [9]	4.05%	0.686	10.61%	13.72%	11.32%	13.46%
Mean					10.72%	12.85%

Notes:
[1] See Notes [7], [8], and [9]
[2] Source: Schedule (RBH)-4
[3] Source: Schedule (RBH)-3
[4] Source: Schedule (RBH)-3
[5] Equals Col. [1] + (Col. [2] x Col. [3])
[6] Equals Col. [1] + (Col. [2] x Col. [4])
[7] Source: Bloomberg Professional
[8] Source: Blue Chip Financial Forecasts, Vol. 38, No. 3, March 1, 2019, at 2.
[9] Source: Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14.

Bond Yield Plus Risk Premium

	[1]	[2]	[3]	[4]	[5]
	Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
	-2.75%	-2.75%			
Current 30-Year Treasury			3.03%	6.85%	9.89%
Near-Term Projected 30-Year Treasury			3.25%	6.66%	9.91%
Long-Term Projected 30-Year Treasury			4.05%	6.06%	10.11%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional
Near Term Projected = Blue Chip Financial Forecasts, Vol. 38, No. 3, March 1, 2019, at 2.
Long Term Projected = Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14.
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: S&P Global Market Intelligence
[7] Source: S&P Global Market Intelligence
[8] Source: Bloomberg Professional, equals 187-trading day average (i.e. lag period)
[9] Equals [7] - [8]

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/3/1980	12.55%	9.40%	3.15%
1/4/1980	13.75%	9.40%	4.35%
1/14/1980	13.20%	9.45%	3.75%
1/18/1980	14.00%	9.48%	4.52%
1/31/1980	12.61%	9.56%	3.05%
2/8/1980	14.50%	9.63%	4.87%
2/14/1980	13.00%	9.68%	3.32%
2/15/1980	13.00%	9.69%	3.31%
2/29/1980	14.00%	9.86%	4.14%
3/5/1980	14.00%	9.91%	4.09%
3/7/1980	13.50%	9.95%	3.55%
3/14/1980	14.00%	10.04%	3.96%
3/27/1980	12.69%	10.21%	2.48%
4/1/1980	14.75%	10.27%	4.48%
4/29/1980	12.50%	10.51%	1.99%
5/7/1980	14.27%	10.56%	3.71%
5/8/1980	13.75%	10.57%	3.18%
5/19/1980	15.50%	10.63%	4.87%
5/27/1980	14.60%	10.66%	3.94%
5/29/1980	16.00%	10.68%	5.32%
6/10/1980	13.78%	10.72%	3.06%
6/25/1980	14.25%	10.74%	3.51%
7/9/1980	14.51%	10.78%	3.73%
7/17/1980	12.90%	10.79%	2.11%
7/18/1980	13.80%	10.80%	3.00%
7/22/1980	14.10%	10.80%	3.30%
7/23/1980	14.19%	10.79%	3.40%
8/1/1980	12.50%	10.80%	1.70%
8/11/1980	14.85%	10.82%	4.03%
8/21/1980	13.03%	10.85%	2.18%
8/28/1980	13.61%	10.88%	2.73%
8/28/1980	14.00%	10.88%	3.12%
9/4/1980	14.00%	10.90%	3.10%
9/24/1980	15.00%	10.99%	4.01%
10/9/1980	14.50%	11.06%	3.44%
10/9/1980	14.50%	11.06%	3.44%
10/24/1980	14.00%	11.09%	2.91%
10/27/1980	15.20%	11.10%	4.10%
10/27/1980	15.20%	11.10%	4.10%
10/28/1980	12.00%	11.10%	0.90%
10/28/1980	13.00%	11.10%	1.90%
10/31/1980	14.50%	11.12%	3.38%
11/4/1980	15.00%	11.12%	3.88%
11/6/1980	14.35%	11.13%	3.22%
11/10/1980	13.25%	11.14%	2.11%
11/17/1980	15.50%	11.14%	4.36%
11/19/1980	13.50%	11.13%	2.37%
12/5/1980	14.60%	11.13%	3.47%
12/8/1980	16.40%	11.13%	5.27%
12/12/1980	15.45%	11.14%	4.31%
12/17/1980	14.40%	11.15%	3.25%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/17/1980	14.20%	11.15%	3.05%
12/18/1980	14.00%	11.16%	2.84%
12/22/1980	13.45%	11.15%	2.30%
12/26/1980	14.00%	11.14%	2.86%
12/30/1980	14.50%	11.13%	3.37%
12/31/1980	14.56%	11.13%	3.43%
1/7/1981	14.30%	11.13%	3.17%
1/12/1981	14.95%	11.14%	3.81%
1/26/1981	15.25%	11.20%	4.05%
1/30/1981	13.25%	11.24%	2.01%
2/11/1981	14.50%	11.34%	3.16%
2/20/1981	14.50%	11.40%	3.10%
3/12/1981	15.65%	11.61%	4.04%
3/25/1981	15.30%	11.75%	3.55%
4/1/1981	15.30%	11.83%	3.47%
4/9/1981	15.00%	11.92%	3.08%
4/29/1981	13.50%	12.13%	1.37%
4/29/1981	14.25%	12.13%	2.12%
4/30/1981	15.00%	12.15%	2.85%
4/30/1981	13.60%	12.15%	1.45%
5/21/1981	14.00%	12.38%	1.62%
6/3/1981	14.67%	12.46%	2.21%
6/22/1981	16.00%	12.58%	3.42%
6/25/1981	14.75%	12.61%	2.14%
7/2/1981	14.00%	12.65%	1.35%
7/10/1981	16.00%	12.70%	3.30%
7/14/1981	16.90%	12.72%	4.18%
7/21/1981	15.78%	12.78%	3.00%
7/27/1981	13.77%	12.83%	0.94%
7/27/1981	15.50%	12.83%	2.67%
7/31/1981	14.20%	12.87%	1.33%
7/31/1981	13.50%	12.87%	0.63%
8/12/1981	13.72%	12.94%	0.78%
8/12/1981	13.72%	12.94%	0.78%
8/12/1981	14.41%	12.94%	1.47%
8/25/1981	15.45%	13.02%	2.43%
8/27/1981	14.43%	13.05%	1.38%
8/28/1981	15.00%	13.06%	1.94%
9/23/1981	14.34%	13.25%	1.09%
9/24/1981	16.25%	13.26%	2.99%
9/29/1981	14.50%	13.31%	1.19%
9/30/1981	15.94%	13.33%	2.61%
10/2/1981	14.80%	13.37%	1.43%
10/12/1981	16.25%	13.43%	2.82%
10/20/1981	15.25%	13.51%	1.74%
10/20/1981	16.50%	13.51%	2.99%
10/20/1981	17.00%	13.51%	3.49%
10/23/1981	15.50%	13.55%	1.95%
10/26/1981	13.50%	13.56%	-0.06%
10/29/1981	16.50%	13.60%	2.90%
11/4/1981	15.33%	13.63%	1.70%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
11/6/1981	15.17%	13.64%	1.53%
11/12/1981	15.00%	13.65%	1.35%
11/25/1981	16.10%	13.66%	2.44%
11/25/1981	16.10%	13.66%	2.44%
11/25/1981	15.25%	13.66%	1.59%
11/30/1981	16.75%	13.66%	3.09%
12/1/1981	15.70%	13.66%	2.04%
12/1/1981	16.00%	13.66%	2.34%
12/15/1981	15.81%	13.70%	2.11%
12/17/1981	14.75%	13.71%	1.04%
12/22/1981	16.00%	13.72%	2.28%
12/22/1981	15.70%	13.72%	1.98%
12/30/1981	16.00%	13.75%	2.25%
12/30/1981	16.25%	13.75%	2.50%
1/4/1982	15.50%	13.75%	1.75%
1/14/1982	11.95%	13.81%	-1.86%
1/25/1982	16.25%	13.84%	2.41%
1/27/1982	16.84%	13.85%	2.99%
1/31/1982	14.00%	13.86%	0.14%
2/2/1982	16.24%	13.86%	2.38%
2/8/1982	15.50%	13.88%	1.62%
2/9/1982	14.95%	13.88%	1.07%
2/9/1982	15.75%	13.88%	1.87%
2/11/1982	16.00%	13.89%	2.11%
3/1/1982	15.96%	13.91%	2.05%
3/3/1982	15.00%	13.92%	1.08%
3/8/1982	17.10%	13.92%	3.18%
3/26/1982	16.00%	13.97%	2.03%
3/31/1982	16.25%	13.98%	2.27%
4/1/1982	16.50%	13.98%	2.52%
4/6/1982	15.00%	13.99%	1.01%
4/9/1982	16.50%	13.99%	2.51%
4/12/1982	15.10%	13.99%	1.11%
4/12/1982	16.70%	13.99%	2.71%
4/18/1982	14.70%	13.99%	0.71%
4/27/1982	15.00%	13.97%	1.03%
5/10/1982	14.57%	13.94%	0.63%
5/14/1982	15.80%	13.92%	1.88%
5/20/1982	15.82%	13.91%	1.91%
5/21/1982	15.50%	13.90%	1.60%
5/25/1982	16.25%	13.89%	2.36%
6/2/1982	14.50%	13.86%	0.64%
6/7/1982	16.00%	13.85%	2.15%
6/23/1982	15.50%	13.81%	1.69%
6/25/1982	16.50%	13.81%	2.69%
7/1/1982	16.00%	13.79%	2.21%
7/1/1982	15.55%	13.79%	1.76%
7/2/1982	15.10%	13.78%	1.32%
7/13/1982	16.80%	13.75%	3.05%
7/22/1982	14.50%	13.71%	0.79%
7/28/1982	16.10%	13.67%	2.43%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
7/30/1982	14.82%	13.66%	1.16%
8/4/1982	15.58%	13.64%	1.94%
8/6/1982	16.50%	13.63%	2.87%
8/11/1982	17.11%	13.62%	3.49%
8/25/1982	16.00%	13.59%	2.41%
8/30/1982	16.25%	13.58%	2.67%
9/3/1982	15.50%	13.57%	1.93%
9/9/1982	16.04%	13.55%	2.49%
9/15/1982	16.04%	13.52%	2.52%
9/17/1982	15.25%	13.51%	1.74%
9/29/1982	14.50%	13.43%	1.07%
9/30/1982	16.50%	13.42%	3.08%
9/30/1982	16.70%	13.42%	3.28%
9/30/1982	15.50%	13.42%	2.08%
9/30/1982	14.74%	13.42%	1.32%
10/1/1982	16.50%	13.40%	3.10%
10/8/1982	15.00%	13.33%	1.67%
10/15/1982	15.90%	13.25%	2.65%
10/19/1982	15.90%	13.22%	2.68%
10/27/1982	17.00%	13.12%	3.88%
10/28/1982	14.75%	13.10%	1.65%
11/2/1982	16.25%	13.07%	3.18%
11/4/1982	15.75%	13.02%	2.73%
11/5/1982	14.73%	13.00%	1.73%
11/17/1982	16.00%	12.86%	3.14%
11/23/1982	15.50%	12.79%	2.71%
11/24/1982	16.02%	12.77%	3.25%
11/24/1982	14.50%	12.77%	1.73%
11/30/1982	15.50%	12.72%	2.78%
11/30/1982	16.10%	12.72%	3.38%
11/30/1982	15.50%	12.72%	2.78%
11/30/1982	12.98%	12.72%	0.26%
11/30/1982	15.65%	12.72%	2.93%
11/30/1982	16.00%	12.72%	3.28%
12/3/1982	15.33%	12.68%	2.65%
12/8/1982	15.75%	12.63%	3.12%
12/13/1982	16.00%	12.58%	3.42%
12/14/1982	16.40%	12.56%	3.84%
12/17/1982	16.25%	12.52%	3.73%
12/20/1982	15.00%	12.50%	2.50%
12/21/1982	15.70%	12.49%	3.21%
12/28/1982	15.25%	12.42%	2.83%
12/28/1982	15.25%	12.42%	2.83%
12/29/1982	16.25%	12.40%	3.85%
12/29/1982	16.25%	12.40%	3.85%
1/11/1983	15.90%	12.25%	3.65%
1/12/1983	15.50%	12.24%	3.26%
1/18/1983	15.00%	12.18%	2.82%
1/24/1983	16.00%	12.13%	3.87%
1/24/1983	15.50%	12.13%	3.37%
1/28/1983	14.90%	12.07%	2.83%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/31/1983	15.00%	12.06%	2.94%
2/10/1983	15.00%	11.97%	3.03%
2/25/1983	15.70%	11.83%	3.87%
3/2/1983	15.25%	11.78%	3.47%
3/16/1983	16.00%	11.61%	4.39%
3/21/1983	14.96%	11.55%	3.41%
3/23/1983	15.40%	11.52%	3.88%
3/23/1983	16.10%	11.52%	4.58%
3/24/1983	15.00%	11.50%	3.50%
4/12/1983	13.25%	11.29%	1.96%
4/29/1983	15.05%	11.08%	3.97%
5/3/1983	15.40%	11.05%	4.35%
5/9/1983	15.50%	10.99%	4.51%
5/19/1983	14.85%	10.89%	3.96%
5/31/1983	14.00%	10.83%	3.17%
6/2/1983	14.50%	10.81%	3.69%
6/7/1983	14.50%	10.79%	3.71%
6/9/1983	14.85%	10.78%	4.07%
6/20/1983	14.15%	10.73%	3.42%
6/20/1983	16.50%	10.73%	5.77%
6/27/1983	14.50%	10.71%	3.79%
6/30/1983	14.80%	10.70%	4.10%
6/30/1983	15.90%	10.70%	5.20%
7/1/1983	14.80%	10.69%	4.11%
7/5/1983	15.00%	10.69%	4.31%
7/8/1983	15.50%	10.69%	4.81%
7/19/1983	15.10%	10.70%	4.40%
7/19/1983	15.00%	10.70%	4.30%
8/18/1983	15.30%	10.81%	4.49%
8/19/1983	15.79%	10.82%	4.97%
8/29/1983	16.00%	10.85%	5.15%
8/31/1983	15.25%	10.87%	4.38%
8/31/1983	14.75%	10.87%	3.88%
9/8/1983	14.75%	10.90%	3.85%
9/16/1983	15.51%	10.93%	4.58%
9/26/1983	14.50%	10.96%	3.54%
9/28/1983	14.25%	10.97%	3.28%
9/30/1983	16.15%	10.98%	5.17%
9/30/1983	16.25%	10.98%	5.27%
10/1/1983	16.25%	10.98%	5.27%
10/13/1983	15.52%	11.02%	4.50%
10/19/1983	15.20%	11.04%	4.16%
10/26/1983	14.75%	11.07%	3.68%
10/27/1983	15.33%	11.07%	4.26%
10/27/1983	14.88%	11.07%	3.81%
11/9/1983	14.82%	11.10%	3.72%
11/9/1983	16.51%	11.10%	5.41%
11/9/1983	16.51%	11.10%	5.41%
12/1/1983	14.50%	11.17%	3.33%
12/8/1983	15.90%	11.21%	4.69%
12/9/1983	15.30%	11.21%	4.09%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/12/1983	14.50%	11.22%	3.28%
12/12/1983	15.50%	11.22%	4.28%
12/20/1983	16.00%	11.26%	4.74%
12/20/1983	15.40%	11.26%	4.14%
12/22/1983	15.75%	11.27%	4.48%
12/29/1983	15.00%	11.30%	3.70%
12/30/1983	15.00%	11.30%	3.70%
1/10/1984	15.90%	11.34%	4.56%
1/13/1984	15.50%	11.37%	4.13%
1/18/1984	15.53%	11.39%	4.14%
1/26/1984	15.90%	11.42%	4.48%
2/14/1984	14.25%	11.52%	2.73%
2/28/1984	14.50%	11.59%	2.91%
3/20/1984	16.00%	11.70%	4.30%
3/23/1984	15.50%	11.73%	3.77%
4/9/1984	15.20%	11.81%	3.39%
4/18/1984	16.20%	11.86%	4.34%
4/27/1984	15.85%	11.90%	3.95%
5/15/1984	13.35%	11.99%	1.36%
5/16/1984	15.00%	12.00%	3.00%
5/22/1984	14.40%	12.04%	2.36%
6/13/1984	15.50%	12.19%	3.31%
7/10/1984	16.00%	12.37%	3.63%
8/7/1984	16.69%	12.51%	4.18%
8/9/1984	15.33%	12.52%	2.81%
8/17/1984	14.82%	12.54%	2.28%
8/21/1984	14.64%	12.55%	2.09%
8/27/1984	14.52%	12.57%	1.95%
8/28/1984	14.75%	12.57%	2.18%
8/30/1984	15.60%	12.58%	3.02%
9/12/1984	15.90%	12.60%	3.30%
9/12/1984	15.60%	12.60%	3.00%
9/25/1984	16.25%	12.62%	3.63%
10/2/1984	14.80%	12.63%	2.17%
10/9/1984	14.75%	12.64%	2.11%
10/10/1984	15.50%	12.64%	2.86%
10/18/1984	15.00%	12.65%	2.35%
10/24/1984	15.50%	12.65%	2.85%
11/7/1984	15.00%	12.64%	2.36%
11/20/1984	15.92%	12.63%	3.29%
11/30/1984	15.50%	12.60%	2.90%
12/18/1984	15.00%	12.55%	2.45%
12/20/1984	15.00%	12.54%	2.46%
12/28/1984	15.75%	12.51%	3.24%
12/28/1984	16.25%	12.51%	3.74%
1/2/1985	16.00%	12.50%	3.50%
1/31/1985	14.75%	12.37%	2.38%
2/7/1985	14.85%	12.32%	2.53%
2/15/1985	15.00%	12.26%	2.74%
2/20/1985	14.50%	12.24%	2.26%
2/22/1985	14.86%	12.24%	2.62%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
3/14/1985	15.50%	12.15%	3.35%
3/28/1985	14.80%	12.08%	2.72%
4/9/1985	15.50%	12.01%	3.49%
4/16/1985	15.70%	11.96%	3.74%
6/10/1985	15.75%	11.58%	4.17%
6/26/1985	14.82%	11.46%	3.36%
7/9/1985	15.00%	11.38%	3.62%
7/26/1985	14.50%	11.26%	3.24%
8/29/1985	14.50%	11.11%	3.39%
8/30/1985	14.38%	11.10%	3.28%
9/12/1985	15.25%	11.07%	4.18%
9/23/1985	15.30%	11.03%	4.27%
9/25/1985	14.50%	11.02%	3.48%
9/26/1985	13.80%	11.01%	2.79%
9/26/1985	14.50%	11.01%	3.49%
10/25/1985	15.25%	10.91%	4.34%
11/8/1985	12.94%	10.85%	2.09%
11/20/1985	14.90%	10.81%	4.09%
11/25/1985	13.30%	10.79%	2.51%
12/6/1985	12.00%	10.71%	1.29%
12/11/1985	14.90%	10.67%	4.23%
12/20/1985	15.00%	10.58%	4.42%
12/20/1985	14.88%	10.58%	4.30%
12/20/1985	15.00%	10.58%	4.42%
12/30/1985	15.75%	10.52%	5.23%
12/31/1985	14.00%	10.51%	3.49%
12/31/1985	14.50%	10.51%	3.99%
1/17/1986	14.50%	10.37%	4.13%
2/11/1986	12.50%	10.20%	2.30%
2/12/1986	15.20%	10.19%	5.01%
3/11/1986	14.00%	9.97%	4.03%
4/2/1986	12.90%	9.76%	3.14%
4/28/1986	13.01%	9.46%	3.55%
5/21/1986	13.25%	9.17%	4.08%
5/28/1986	14.00%	9.11%	4.89%
5/29/1986	13.90%	9.10%	4.80%
6/2/1986	13.00%	9.07%	3.93%
6/11/1986	14.00%	8.96%	5.04%
6/13/1986	13.55%	8.93%	4.62%
6/27/1986	11.88%	8.76%	3.12%
7/14/1986	12.60%	8.57%	4.03%
7/30/1986	13.30%	8.37%	4.93%
8/14/1986	13.50%	8.21%	5.29%
9/5/1986	13.30%	8.01%	5.29%
9/23/1986	12.75%	7.90%	4.85%
10/30/1986	13.00%	7.66%	5.34%
10/31/1986	13.75%	7.65%	6.10%
11/10/1986	14.00%	7.60%	6.40%
11/19/1986	13.75%	7.56%	6.19%
11/25/1986	13.15%	7.54%	5.61%
12/22/1986	13.80%	7.47%	6.33%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/30/1986	13.90%	7.47%	6.43%
1/20/1987	12.75%	7.47%	5.28%
1/23/1987	13.55%	7.47%	6.08%
1/27/1987	12.16%	7.47%	4.69%
2/13/1987	12.60%	7.47%	5.13%
2/24/1987	12.00%	7.47%	4.53%
3/30/1987	12.20%	7.46%	4.74%
3/31/1987	13.00%	7.47%	5.53%
5/5/1987	12.85%	7.60%	5.25%
5/28/1987	13.50%	7.73%	5.77%
6/15/1987	13.20%	7.81%	5.39%
6/30/1987	12.60%	7.85%	4.75%
7/10/1987	12.90%	7.88%	5.02%
7/27/1987	13.50%	7.94%	5.56%
8/25/1987	11.40%	8.09%	3.31%
9/18/1987	13.00%	8.28%	4.72%
10/20/1987	12.60%	8.55%	4.05%
10/20/1987	12.98%	8.55%	4.43%
11/12/1987	12.75%	8.68%	4.07%
11/13/1987	12.75%	8.69%	4.06%
11/24/1987	12.50%	8.74%	3.76%
12/8/1987	12.50%	8.82%	3.68%
12/22/1987	12.00%	8.91%	3.09%
12/31/1987	13.25%	8.95%	4.30%
12/31/1987	12.85%	8.95%	3.90%
1/15/1988	13.15%	8.99%	4.16%
1/20/1988	12.75%	8.99%	3.76%
1/29/1988	13.20%	8.99%	4.21%
2/4/1988	12.60%	8.99%	3.61%
3/23/1988	13.00%	8.95%	4.05%
5/27/1988	13.18%	9.02%	4.16%
6/14/1988	13.50%	9.00%	4.50%
6/17/1988	11.72%	8.98%	2.74%
6/24/1988	11.50%	8.97%	2.53%
7/1/1988	12.75%	8.94%	3.81%
7/8/1988	12.00%	8.93%	3.07%
7/18/1988	12.00%	8.90%	3.10%
7/20/1988	13.40%	8.89%	4.51%
8/8/1988	12.74%	8.90%	3.84%
9/20/1988	12.90%	8.93%	3.97%
9/26/1988	12.40%	8.93%	3.47%
9/27/1988	13.65%	8.93%	4.72%
9/30/1988	13.25%	8.94%	4.31%
10/13/1988	13.10%	8.93%	4.17%
10/21/1988	12.80%	8.94%	3.86%
10/25/1988	13.25%	8.94%	4.31%
10/26/1988	13.50%	8.94%	4.56%
10/27/1988	12.95%	8.95%	4.00%
10/28/1988	13.00%	8.95%	4.05%
11/15/1988	12.00%	8.98%	3.02%
11/29/1988	12.75%	9.02%	3.73%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/19/1988	13.00%	9.05%	3.95%
12/21/1988	12.90%	9.05%	3.85%
12/22/1988	13.50%	9.06%	4.44%
1/26/1989	12.60%	9.06%	3.54%
1/27/1989	13.00%	9.06%	3.94%
2/8/1989	13.37%	9.05%	4.32%
3/8/1989	13.00%	9.04%	3.96%
5/4/1989	13.00%	9.04%	3.96%
6/8/1989	13.50%	8.96%	4.54%
7/19/1989	11.80%	8.84%	2.96%
7/25/1989	12.80%	8.82%	3.98%
7/31/1989	13.00%	8.81%	4.19%
8/14/1989	12.50%	8.76%	3.74%
8/22/1989	12.80%	8.73%	4.07%
8/23/1989	12.90%	8.72%	4.18%
9/21/1989	12.10%	8.62%	3.48%
10/6/1989	13.00%	8.57%	4.43%
10/17/1989	12.41%	8.54%	3.87%
10/18/1989	13.25%	8.54%	4.71%
10/20/1989	12.90%	8.53%	4.37%
10/31/1989	13.60%	8.49%	5.11%
11/3/1989	12.93%	8.48%	4.45%
11/5/1989	13.20%	8.48%	4.72%
11/9/1989	12.60%	8.45%	4.15%
11/9/1989	13.00%	8.45%	4.55%
11/28/1989	12.75%	8.37%	4.38%
12/7/1989	13.25%	8.32%	4.93%
12/15/1989	13.00%	8.27%	4.73%
12/20/1989	12.90%	8.25%	4.65%
12/21/1989	12.80%	8.25%	4.55%
12/21/1989	12.90%	8.25%	4.65%
12/27/1989	12.50%	8.23%	4.27%
1/9/1990	13.00%	8.19%	4.81%
1/18/1990	12.50%	8.16%	4.34%
1/26/1990	12.10%	8.14%	3.96%
3/21/1990	12.80%	8.15%	4.65%
3/28/1990	13.00%	8.16%	4.84%
4/5/1990	12.20%	8.17%	4.03%
4/12/1990	13.25%	8.19%	5.06%
4/30/1990	12.45%	8.24%	4.21%
5/31/1990	12.40%	8.31%	4.09%
6/15/1990	13.20%	8.33%	4.87%
6/27/1990	12.90%	8.34%	4.56%
6/29/1990	13.25%	8.35%	4.90%
7/6/1990	12.10%	8.36%	3.74%
7/19/1990	11.70%	8.39%	3.31%
8/31/1990	12.50%	8.53%	3.97%
8/31/1990	12.50%	8.53%	3.97%
9/13/1990	12.50%	8.58%	3.92%
9/18/1990	12.75%	8.60%	4.15%
9/20/1990	12.50%	8.61%	3.89%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
10/2/1990	13.00%	8.65%	4.35%
10/17/1990	11.90%	8.68%	3.22%
10/31/1990	12.95%	8.70%	4.25%
11/9/1990	13.25%	8.71%	4.54%
11/19/1990	13.00%	8.70%	4.30%
11/21/1990	12.50%	8.70%	3.80%
11/21/1990	12.10%	8.70%	3.40%
11/28/1990	12.75%	8.70%	4.05%
11/29/1990	12.75%	8.70%	4.05%
12/18/1990	13.10%	8.68%	4.42%
12/20/1990	12.50%	8.67%	3.83%
12/21/1990	13.60%	8.67%	4.93%
12/21/1990	13.00%	8.67%	4.33%
12/21/1990	12.50%	8.67%	3.83%
1/3/1991	13.02%	8.66%	4.36%
1/16/1991	13.25%	8.63%	4.62%
1/25/1991	11.70%	8.60%	3.10%
2/15/1991	12.70%	8.56%	4.14%
2/15/1991	12.80%	8.56%	4.24%
4/3/1991	13.00%	8.51%	4.49%
4/30/1991	12.45%	8.47%	3.98%
4/30/1991	13.00%	8.47%	4.53%
6/25/1991	11.70%	8.34%	3.36%
6/28/1991	12.50%	8.33%	4.17%
7/1/1991	11.70%	8.33%	3.37%
7/19/1991	12.10%	8.30%	3.80%
7/19/1991	12.30%	8.30%	4.00%
7/22/1991	12.90%	8.30%	4.60%
8/15/1991	12.25%	8.27%	3.98%
8/29/1991	13.30%	8.26%	5.04%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.40%	8.23%	4.17%
10/3/1991	11.30%	8.22%	3.08%
10/9/1991	11.70%	8.21%	3.49%
10/15/1991	13.40%	8.20%	5.20%
11/1/1991	12.90%	8.20%	4.70%
11/8/1991	12.75%	8.20%	4.55%
11/26/1991	12.00%	8.18%	3.82%
11/26/1991	11.60%	8.18%	3.42%
11/27/1991	12.70%	8.18%	4.52%
12/6/1991	12.70%	8.16%	4.54%
12/10/1991	11.75%	8.15%	3.60%
12/19/1991	12.60%	8.14%	4.46%
12/19/1991	12.80%	8.14%	4.66%
12/30/1991	12.10%	8.11%	3.99%
1/22/1992	12.84%	8.05%	4.79%
1/31/1992	12.00%	8.03%	3.97%
2/20/1992	13.00%	8.00%	5.00%
2/27/1992	11.75%	7.98%	3.77%
3/18/1992	12.50%	7.94%	4.56%
5/15/1992	12.75%	7.86%	4.89%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/24/1992	12.20%	7.85%	4.35%
6/29/1992	11.00%	7.85%	3.15%
7/14/1992	12.00%	7.83%	4.17%
7/22/1992	11.20%	7.82%	3.38%
8/10/1992	12.10%	7.79%	4.31%
8/26/1992	12.43%	7.75%	4.68%
9/30/1992	11.60%	7.72%	3.88%
10/6/1992	12.25%	7.72%	4.53%
10/13/1992	12.75%	7.71%	5.04%
10/23/1992	11.65%	7.71%	3.94%
10/28/1992	12.25%	7.71%	4.54%
10/29/1992	12.75%	7.70%	5.05%
10/30/1992	11.40%	7.70%	3.70%
11/9/1992	10.60%	7.70%	2.90%
11/25/1992	12.00%	7.67%	4.33%
11/25/1992	11.00%	7.67%	3.33%
12/3/1992	11.85%	7.66%	4.19%
12/16/1992	11.90%	7.63%	4.27%
12/22/1992	12.40%	7.62%	4.78%
12/22/1992	12.30%	7.62%	4.68%
12/30/1992	12.00%	7.61%	4.39%
12/31/1992	12.00%	7.60%	4.40%
1/12/1993	12.00%	7.58%	4.42%
1/12/1993	12.00%	7.58%	4.42%
2/2/1993	11.40%	7.53%	3.87%
2/22/1993	11.60%	7.47%	4.13%
4/23/1993	11.75%	7.27%	4.48%
5/3/1993	11.75%	7.25%	4.50%
5/3/1993	11.50%	7.25%	4.25%
6/3/1993	12.00%	7.20%	4.80%
6/7/1993	11.50%	7.20%	4.30%
6/22/1993	11.75%	7.16%	4.59%
7/21/1993	11.78%	7.06%	4.72%
7/21/1993	11.90%	7.06%	4.84%
7/23/1993	11.50%	7.05%	4.45%
7/29/1993	11.50%	7.03%	4.47%
8/12/1993	10.75%	6.97%	3.78%
8/24/1993	11.50%	6.91%	4.59%
8/31/1993	11.90%	6.88%	5.02%
9/1/1993	11.25%	6.87%	4.38%
9/1/1993	11.47%	6.87%	4.60%
9/27/1993	10.50%	6.74%	3.76%
9/29/1993	11.00%	6.72%	4.28%
9/30/1993	11.60%	6.71%	4.89%
10/8/1993	11.50%	6.67%	4.83%
10/14/1993	11.20%	6.65%	4.55%
10/15/1993	11.75%	6.64%	5.11%
10/25/1993	11.55%	6.60%	4.95%
10/28/1993	11.50%	6.58%	4.92%
10/29/1993	11.25%	6.57%	4.68%
10/29/1993	10.20%	6.57%	3.63%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
10/29/1993	10.10%	6.57%	3.53%
11/2/1993	10.80%	6.56%	4.24%
11/12/1993	11.80%	6.53%	5.27%
11/23/1993	12.50%	6.50%	6.00%
11/26/1993	11.00%	6.50%	4.50%
12/1/1993	11.45%	6.49%	4.96%
12/16/1993	11.20%	6.45%	4.75%
12/16/1993	10.60%	6.45%	4.15%
12/21/1993	11.30%	6.44%	4.86%
12/22/1993	11.00%	6.44%	4.56%
12/23/1993	10.10%	6.43%	3.67%
1/5/1994	11.50%	6.41%	5.09%
1/10/1994	11.00%	6.40%	4.60%
1/25/1994	12.00%	6.37%	5.63%
2/2/1994	10.40%	6.35%	4.05%
2/9/1994	10.70%	6.33%	4.37%
4/6/1994	11.24%	6.34%	4.90%
4/25/1994	11.00%	6.39%	4.61%
6/16/1994	10.50%	6.64%	3.86%
6/23/1994	10.60%	6.68%	3.92%
7/19/1994	10.70%	6.84%	3.86%
9/29/1994	11.00%	7.21%	3.79%
9/29/1994	10.90%	7.21%	3.69%
10/7/1994	11.87%	7.26%	4.61%
10/18/1994	11.50%	7.32%	4.18%
10/18/1994	11.50%	7.32%	4.18%
10/24/1994	11.00%	7.36%	3.64%
11/22/1994	12.12%	7.53%	4.59%
11/29/1994	11.30%	7.55%	3.75%
12/1/1994	11.00%	7.57%	3.43%
12/8/1994	11.70%	7.59%	4.11%
12/8/1994	11.50%	7.59%	3.91%
12/12/1994	11.82%	7.60%	4.22%
12/14/1994	11.50%	7.61%	3.89%
12/19/1994	11.50%	7.62%	3.88%
4/19/1995	11.00%	7.72%	3.28%
9/11/1995	11.30%	7.16%	4.14%
9/15/1995	10.40%	7.13%	3.27%
9/29/1995	11.50%	7.06%	4.44%
10/13/1995	10.76%	6.98%	3.78%
11/7/1995	12.50%	6.86%	5.64%
11/8/1995	11.30%	6.85%	4.45%
11/8/1995	11.10%	6.85%	4.25%
11/17/1995	10.90%	6.80%	4.10%
11/20/1995	11.40%	6.80%	4.60%
11/27/1995	13.60%	6.76%	6.84%
12/14/1995	11.30%	6.67%	4.63%
12/20/1995	11.60%	6.64%	4.96%
1/31/1996	11.30%	6.45%	4.85%
3/11/1996	11.60%	6.40%	5.20%
4/3/1996	11.13%	6.40%	4.73%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
4/15/1996	10.50%	6.40%	4.10%
4/17/1996	10.77%	6.40%	4.37%
4/26/1996	10.60%	6.40%	4.20%
5/10/1996	11.00%	6.40%	4.60%
5/13/1996	11.25%	6.40%	4.85%
7/3/1996	11.25%	6.49%	4.76%
7/22/1996	11.25%	6.54%	4.71%
10/3/1996	10.00%	6.77%	3.23%
10/29/1996	11.30%	6.85%	4.45%
11/26/1996	11.30%	6.86%	4.44%
11/27/1996	11.30%	6.86%	4.44%
11/29/1996	11.00%	6.86%	4.14%
12/12/1996	11.96%	6.85%	5.11%
12/17/1996	11.50%	6.85%	4.65%
1/22/1997	11.30%	6.83%	4.47%
1/27/1997	11.25%	6.83%	4.42%
1/31/1997	11.25%	6.83%	4.42%
2/13/1997	11.00%	6.82%	4.18%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.81%	4.99%
3/27/1997	10.75%	6.79%	3.96%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
10/29/1997	10.75%	6.70%	4.05%
10/31/1997	11.25%	6.70%	4.55%
12/24/1997	10.75%	6.53%	4.22%
4/28/1998	10.90%	6.10%	4.80%
4/30/1998	12.20%	6.10%	6.10%
6/30/1998	11.00%	5.94%	5.06%
8/26/1998	10.93%	5.82%	5.11%
9/3/1998	11.40%	5.80%	5.60%
9/15/1998	11.90%	5.77%	6.13%
10/7/1998	11.06%	5.70%	5.36%
10/30/1998	11.40%	5.63%	5.77%
12/10/1998	12.20%	5.51%	6.69%
12/17/1998	12.10%	5.49%	6.61%
2/19/1999	11.15%	5.31%	5.84%
3/1/1999	10.65%	5.31%	5.34%
3/1/1999	10.65%	5.31%	5.34%
6/8/1999	11.25%	5.36%	5.89%
11/12/1999	10.25%	5.92%	4.33%
12/14/1999	10.50%	6.00%	4.50%
1/28/2000	10.71%	6.16%	4.55%
2/17/2000	10.60%	6.20%	4.40%
5/25/2000	10.80%	6.20%	4.60%
6/19/2000	11.05%	6.18%	4.87%
6/22/2000	11.25%	6.18%	5.07%
7/17/2000	11.06%	6.15%	4.91%
7/20/2000	12.20%	6.14%	6.06%
8/11/2000	11.00%	6.11%	4.89%
9/27/2000	11.25%	6.00%	5.25%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
9/29/2000	11.16%	5.99%	5.17%
10/5/2000	11.30%	5.98%	5.32%
11/28/2000	12.90%	5.87%	7.03%
11/30/2000	12.10%	5.86%	6.24%
2/5/2001	11.50%	5.75%	5.75%
3/15/2001	11.25%	5.66%	5.59%
5/8/2001	10.75%	5.61%	5.14%
10/24/2001	11.00%	5.54%	5.46%
10/24/2001	10.30%	5.54%	4.76%
1/9/2002	10.00%	5.50%	4.50%
1/30/2002	11.00%	5.47%	5.53%
1/31/2002	11.00%	5.47%	5.53%
4/17/2002	11.50%	5.44%	6.06%
4/29/2002	11.00%	5.44%	5.56%
6/11/2002	11.77%	5.47%	6.30%
6/20/2002	12.30%	5.48%	6.82%
8/28/2002	11.00%	5.49%	5.51%
9/11/2002	11.20%	5.45%	5.75%
9/12/2002	12.30%	5.45%	6.85%
10/28/2002	11.30%	5.34%	5.96%
10/30/2002	10.60%	5.34%	5.26%
11/1/2002	12.60%	5.34%	7.26%
11/7/2002	11.40%	5.33%	6.07%
11/8/2002	10.75%	5.33%	5.42%
11/20/2002	10.00%	5.30%	4.70%
11/20/2002	10.50%	5.30%	5.20%
12/4/2002	10.75%	5.26%	5.49%
12/30/2002	11.20%	5.18%	6.02%
1/6/2003	11.25%	5.16%	6.09%
2/28/2003	12.30%	5.00%	7.30%
3/7/2003	9.96%	4.98%	4.98%
3/12/2003	11.40%	4.97%	6.43%
3/20/2003	12.00%	4.95%	7.05%
4/3/2003	12.00%	4.92%	7.08%
5/2/2003	11.40%	4.88%	6.52%
5/15/2003	11.05%	4.87%	6.18%
6/26/2003	11.00%	4.80%	6.20%
7/1/2003	11.00%	4.80%	6.20%
7/29/2003	11.71%	4.78%	6.93%
8/22/2003	10.20%	4.81%	5.39%
9/17/2003	9.90%	4.85%	5.05%
9/25/2003	10.25%	4.85%	5.40%
10/17/2003	10.54%	4.87%	5.67%
10/22/2003	10.46%	4.87%	5.59%
10/22/2003	10.71%	4.87%	5.84%
10/30/2003	11.00%	4.88%	6.12%
10/31/2003	10.20%	4.88%	5.32%
10/31/2003	10.75%	4.88%	5.87%
11/10/2003	10.60%	4.89%	5.71%
12/9/2003	10.50%	4.93%	5.57%
12/18/2003	10.50%	4.94%	5.56%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
1/13/2004	10.25%	4.95%	5.30%
1/13/2004	12.00%	4.95%	7.05%
2/9/2004	11.25%	4.99%	6.26%
3/16/2004	10.90%	5.05%	5.85%
3/16/2004	10.90%	5.05%	5.85%
5/25/2004	10.00%	5.06%	4.94%
6/2/2004	11.22%	5.07%	6.15%
6/30/2004	10.50%	5.10%	5.40%
7/8/2004	10.00%	5.10%	4.90%
7/22/2004	10.25%	5.10%	5.15%
8/26/2004	10.50%	5.10%	5.40%
8/26/2004	10.50%	5.10%	5.40%
9/9/2004	10.40%	5.10%	5.30%
9/21/2004	10.50%	5.09%	5.41%
9/27/2004	10.30%	5.09%	5.21%
9/27/2004	10.50%	5.09%	5.41%
10/20/2004	10.20%	5.08%	5.12%
11/30/2004	10.60%	5.08%	5.52%
12/8/2004	9.90%	5.09%	4.81%
12/21/2004	11.50%	5.09%	6.41%
12/22/2004	11.50%	5.09%	6.41%
12/28/2004	10.25%	5.09%	5.16%
2/18/2005	10.30%	4.95%	5.35%
3/29/2005	11.00%	4.86%	6.14%
4/13/2005	10.60%	4.83%	5.77%
4/28/2005	11.00%	4.80%	6.20%
5/17/2005	10.00%	4.76%	5.24%
6/8/2005	10.18%	4.71%	5.47%
6/10/2005	10.90%	4.71%	6.19%
7/6/2005	10.50%	4.65%	5.85%
7/19/2005	11.50%	4.63%	6.87%
8/11/2005	10.40%	4.60%	5.80%
9/19/2005	9.45%	4.53%	4.92%
9/30/2005	10.51%	4.52%	5.99%
10/4/2005	9.90%	4.52%	5.38%
10/4/2005	10.75%	4.52%	6.23%
10/14/2005	10.40%	4.51%	5.89%
10/31/2005	10.25%	4.53%	5.72%
11/2/2005	9.70%	4.53%	5.17%
11/30/2005	10.00%	4.53%	5.47%
12/9/2005	9.70%	4.53%	5.17%
12/12/2005	11.00%	4.53%	6.47%
12/20/2005	10.13%	4.52%	5.61%
12/21/2005	11.00%	4.52%	6.48%
12/21/2005	10.40%	4.52%	5.88%
12/22/2005	10.20%	4.52%	5.68%
12/22/2005	11.00%	4.52%	6.48%
12/28/2005	10.00%	4.52%	5.48%
1/5/2006	11.00%	4.52%	6.48%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/25/2006	11.20%	4.52%	6.68%
1/25/2006	11.20%	4.52%	6.68%
2/3/2006	10.50%	4.52%	5.98%
2/15/2006	9.50%	4.53%	4.97%
4/26/2006	10.60%	4.65%	5.95%
7/24/2006	9.60%	4.87%	4.73%
7/24/2006	10.00%	4.87%	5.13%
9/20/2006	11.00%	4.93%	6.07%
9/26/2006	10.75%	4.94%	5.81%
10/20/2006	9.80%	4.96%	4.84%
11/2/2006	9.71%	4.97%	4.74%
11/9/2006	10.00%	4.98%	5.02%
11/21/2006	11.00%	4.98%	6.02%
12/5/2006	10.20%	4.97%	5.23%
1/5/2007	10.40%	4.95%	5.45%
1/9/2007	11.00%	4.94%	6.06%
1/11/2007	10.90%	4.94%	5.96%
1/19/2007	10.80%	4.93%	5.87%
1/26/2007	10.00%	4.92%	5.08%
2/8/2007	10.40%	4.91%	5.49%
3/14/2007	10.10%	4.85%	5.25%
3/20/2007	10.25%	4.84%	5.41%
3/21/2007	11.35%	4.84%	6.51%
3/22/2007	10.50%	4.84%	5.66%
3/29/2007	10.00%	4.83%	5.17%
6/13/2007	10.75%	4.82%	5.93%
6/29/2007	10.10%	4.84%	5.26%
6/29/2007	9.53%	4.84%	4.69%
7/3/2007	10.25%	4.85%	5.40%
7/13/2007	9.50%	4.86%	4.64%
7/24/2007	10.40%	4.87%	5.53%
8/1/2007	10.15%	4.88%	5.27%
8/29/2007	10.50%	4.91%	5.59%
9/10/2007	9.71%	4.92%	4.79%
9/19/2007	10.00%	4.91%	5.09%
9/25/2007	9.70%	4.92%	4.78%
10/8/2007	10.48%	4.92%	5.56%
10/19/2007	10.50%	4.91%	5.59%
10/25/2007	9.65%	4.91%	4.74%
11/15/2007	10.00%	4.89%	5.11%
11/20/2007	9.90%	4.89%	5.01%
11/27/2007	10.00%	4.89%	5.11%
11/29/2007	10.90%	4.88%	6.02%
12/14/2007	10.80%	4.87%	5.93%
12/18/2007	10.40%	4.86%	5.54%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	10.20%	4.86%	5.34%
12/21/2007	9.10%	4.86%	4.24%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/17/2008	10.75%	4.81%	5.94%
2/5/2008	9.99%	4.77%	5.22%
2/5/2008	10.19%	4.77%	5.42%
2/13/2008	10.20%	4.76%	5.44%
3/31/2008	10.00%	4.63%	5.37%
5/28/2008	10.50%	4.53%	5.97%
6/24/2008	10.00%	4.52%	5.48%
6/27/2008	10.00%	4.52%	5.48%
7/31/2008	10.70%	4.50%	6.20%
7/31/2008	10.82%	4.50%	6.32%
8/27/2008	10.25%	4.50%	5.75%
9/2/2008	10.25%	4.50%	5.75%
9/19/2008	10.70%	4.48%	6.22%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/30/2008	10.20%	4.48%	5.72%
10/3/2008	10.30%	4.48%	5.82%
10/8/2008	10.15%	4.47%	5.68%
10/20/2008	10.06%	4.47%	5.59%
10/24/2008	10.60%	4.46%	6.14%
10/24/2008	10.60%	4.46%	6.14%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/24/2008	10.50%	4.41%	6.09%
12/3/2008	10.39%	4.38%	6.01%
12/24/2008	10.00%	4.26%	5.74%
12/26/2008	10.10%	4.24%	5.86%
12/29/2008	10.20%	4.23%	5.97%
1/13/2009	10.45%	4.14%	6.31%
2/2/2009	10.05%	4.03%	6.02%
3/9/2009	10.30%	3.89%	6.41%
3/25/2009	10.17%	3.83%	6.34%
4/2/2009	10.75%	3.80%	6.95%
5/5/2009	10.75%	3.71%	7.04%
5/15/2009	10.20%	3.70%	6.50%
5/29/2009	9.54%	3.70%	5.84%
6/3/2009	10.10%	3.70%	6.40%
6/22/2009	10.00%	3.73%	6.27%
6/29/2009	10.21%	3.73%	6.48%
6/30/2009	9.31%	3.74%	5.57%
7/17/2009	9.26%	3.75%	5.51%
7/17/2009	10.50%	3.75%	6.75%
10/16/2009	10.40%	4.09%	6.31%
10/26/2009	10.10%	4.11%	5.99%
10/28/2009	10.15%	4.12%	6.03%
10/28/2009	10.15%	4.12%	6.03%
10/30/2009	9.95%	4.13%	5.82%
11/20/2009	9.45%	4.19%	5.26%
12/14/2009	10.50%	4.25%	6.25%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/16/2009	10.75%	4.26%	6.49%
12/17/2009	10.30%	4.26%	6.04%
12/18/2009	10.40%	4.27%	6.13%
12/18/2009	10.50%	4.27%	6.23%
12/18/2009	10.40%	4.27%	6.13%
12/22/2009	10.20%	4.28%	5.92%
12/22/2009	10.40%	4.28%	6.12%
12/28/2009	10.85%	4.30%	6.55%
12/29/2009	10.38%	4.30%	6.08%
1/11/2010	10.24%	4.34%	5.90%
1/21/2010	10.33%	4.37%	5.96%
1/21/2010	10.23%	4.37%	5.86%
1/26/2010	10.40%	4.37%	6.03%
2/10/2010	10.00%	4.39%	5.61%
2/23/2010	10.50%	4.40%	6.10%
3/9/2010	9.60%	4.40%	5.20%
3/24/2010	10.13%	4.42%	5.71%
3/31/2010	10.70%	4.43%	6.27%
4/1/2010	9.50%	4.43%	5.07%
4/2/2010	10.10%	4.44%	5.66%
4/8/2010	10.35%	4.44%	5.91%
4/29/2010	9.40%	4.46%	4.94%
4/29/2010	9.19%	4.46%	4.73%
4/29/2010	9.40%	4.46%	4.94%
5/17/2010	10.55%	4.46%	6.09%
5/24/2010	10.05%	4.46%	5.59%
6/3/2010	11.00%	4.46%	6.54%
6/16/2010	10.00%	4.46%	5.54%
6/18/2010	10.30%	4.46%	5.84%
8/9/2010	12.55%	4.41%	8.14%
8/17/2010	10.10%	4.40%	5.70%
9/16/2010	10.30%	4.31%	5.99%
9/16/2010	9.60%	4.31%	5.29%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.00%	4.31%	5.69%
10/21/2010	10.40%	4.20%	6.20%
11/2/2010	9.75%	4.17%	5.58%
11/2/2010	9.75%	4.17%	5.58%
11/3/2010	10.75%	4.17%	6.58%
11/19/2010	10.20%	4.14%	6.06%
12/1/2010	10.00%	4.12%	5.88%
12/6/2010	9.56%	4.12%	5.44%
12/6/2010	10.09%	4.12%	5.97%
12/9/2010	10.25%	4.12%	6.13%
12/14/2010	10.33%	4.11%	6.22%
12/17/2010	10.10%	4.11%	5.99%
12/20/2010	10.10%	4.11%	5.99%
12/23/2010	9.92%	4.10%	5.82%
1/6/2011	10.35%	4.09%	6.26%
1/12/2011	10.30%	4.08%	6.22%
1/13/2011	10.30%	4.08%	6.22%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
3/10/2011	10.10%	4.16%	5.94%
3/31/2011	9.45%	4.20%	5.25%
4/18/2011	10.05%	4.24%	5.81%
5/26/2011	10.50%	4.32%	6.18%
6/21/2011	10.00%	4.36%	5.64%
6/29/2011	8.83%	4.38%	4.45%
8/1/2011	9.20%	4.41%	4.79%
9/1/2011	10.10%	4.32%	5.78%
11/14/2011	9.60%	3.93%	5.67%
12/13/2011	9.50%	3.76%	5.74%
12/20/2011	10.00%	3.71%	6.29%
12/22/2011	10.40%	3.70%	6.70%
1/10/2012	9.06%	3.59%	5.47%
1/10/2012	9.45%	3.59%	5.86%
1/10/2012	9.45%	3.59%	5.86%
1/23/2012	10.20%	3.52%	6.68%
1/31/2012	10.00%	3.48%	6.52%
4/24/2012	9.75%	3.15%	6.60%
4/24/2012	9.50%	3.15%	6.35%
5/7/2012	9.80%	3.13%	6.67%
5/22/2012	9.60%	3.10%	6.50%
5/24/2012	9.70%	3.09%	6.61%
6/7/2012	10.30%	3.06%	7.24%
6/15/2012	10.40%	3.05%	7.35%
6/18/2012	9.60%	3.05%	6.55%
7/2/2012	9.75%	3.04%	6.71%
10/24/2012	10.30%	2.92%	7.38%
10/26/2012	9.50%	2.92%	6.58%
10/31/2012	10.00%	2.91%	7.09%
10/31/2012	9.30%	2.91%	6.39%
10/31/2012	9.90%	2.91%	6.99%
11/1/2012	9.45%	2.91%	6.54%
11/8/2012	10.10%	2.91%	7.19%
11/9/2012	10.30%	2.90%	7.40%
11/26/2012	10.00%	2.88%	7.12%
11/28/2012	10.40%	2.88%	7.52%
11/28/2012	10.50%	2.88%	7.62%
12/4/2012	10.50%	2.87%	7.63%
12/4/2012	10.00%	2.87%	7.13%
12/20/2012	10.40%	2.84%	7.56%
12/20/2012	10.30%	2.84%	7.46%
12/20/2012	10.10%	2.84%	7.26%
12/20/2012	10.25%	2.84%	7.41%
12/20/2012	10.50%	2.84%	7.66%
12/20/2012	9.50%	2.84%	6.66%
12/26/2012	9.80%	2.83%	6.97%
2/22/2013	9.60%	2.86%	6.74%
3/14/2013	9.30%	2.89%	6.41%
3/27/2013	9.80%	2.92%	6.88%
4/23/2013	9.80%	2.96%	6.84%
5/10/2013	9.25%	2.96%	6.29%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
6/13/2013	9.40%	3.02%	6.38%
6/18/2013	9.28%	3.02%	6.26%
6/18/2013	9.28%	3.02%	6.26%
6/25/2013	9.80%	3.04%	6.76%
9/23/2013	9.60%	3.33%	6.27%
11/6/2013	10.20%	3.42%	6.78%
11/13/2013	9.84%	3.44%	6.40%
11/14/2013	10.25%	3.45%	6.80%
11/22/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.50%	6.70%
12/13/2013	9.60%	3.52%	6.08%
12/16/2013	9.73%	3.53%	6.20%
12/17/2013	10.00%	3.53%	6.47%
12/18/2013	9.08%	3.54%	5.54%
12/23/2013	9.72%	3.55%	6.17%
12/30/2013	10.00%	3.58%	6.42%
1/21/2014	9.65%	3.66%	5.99%
1/22/2014	9.18%	3.66%	5.52%
2/20/2014	9.30%	3.72%	5.58%
2/21/2014	9.85%	3.72%	6.13%
2/28/2014	9.55%	3.73%	5.82%
3/16/2014	9.72%	3.74%	5.98%
4/21/2014	9.50%	3.73%	5.77%
4/22/2014	9.80%	3.73%	6.07%
5/8/2014	9.59%	3.71%	5.88%
5/8/2014	9.10%	3.71%	5.39%
6/6/2014	10.40%	3.66%	6.74%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
7/7/2014	9.30%	3.63%	5.67%
7/25/2014	9.30%	3.60%	5.70%
7/31/2014	9.90%	3.59%	6.31%
9/4/2014	9.10%	3.50%	5.60%
9/24/2014	9.35%	3.46%	5.89%
9/30/2014	9.75%	3.44%	6.31%
10/29/2014	10.80%	3.37%	7.43%
11/6/2014	10.20%	3.35%	6.85%
11/14/2014	10.20%	3.33%	6.87%
11/14/2014	10.30%	3.33%	6.97%
11/26/2014	10.20%	3.30%	6.90%
12/3/2014	10.00%	3.28%	6.72%
1/13/2015	10.30%	3.16%	7.14%
1/21/2015	9.05%	3.13%	5.92%
1/21/2015	9.05%	3.13%	5.92%
4/9/2015	9.50%	2.88%	6.62%
5/11/2015	9.80%	2.81%	6.99%
6/17/2015	9.00%	2.79%	6.21%
8/21/2015	9.75%	2.78%	6.97%
10/7/2015	9.55%	2.82%	6.73%
10/13/2015	9.75%	2.83%	6.92%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
10/15/2015	9.00%	2.84%	6.16%
10/30/2015	9.80%	2.87%	6.93%
11/19/2015	10.00%	2.90%	7.10%
12/3/2015	10.00%	2.91%	7.09%
12/9/2015	9.60%	2.92%	6.68%
12/11/2015	9.90%	2.93%	6.97%
12/18/2015	9.50%	2.94%	6.56%
1/6/2016	9.50%	2.97%	6.53%
1/6/2016	9.50%	2.97%	6.53%
1/28/2016	9.40%	2.97%	6.43%
2/10/2016	9.60%	2.95%	6.65%
2/16/2016	9.50%	2.94%	6.56%
2/29/2016	9.40%	2.92%	6.48%
4/29/2016	9.80%	2.83%	6.97%
5/5/2016	9.49%	2.82%	6.67%
6/1/2016	9.55%	2.80%	6.75%
6/3/2016	9.65%	2.79%	6.86%
6/15/2016	9.00%	2.77%	6.23%
6/15/2016	9.00%	2.77%	6.23%
9/2/2016	9.50%	2.56%	6.94%
9/23/2016	9.75%	2.51%	7.24%
9/27/2016	9.50%	2.51%	6.99%
9/29/2016	9.11%	2.50%	6.61%
10/13/2016	10.20%	2.48%	7.72%
10/28/2016	9.70%	2.47%	7.23%
11/9/2016	9.80%	2.47%	7.33%
11/18/2016	10.00%	2.49%	7.51%
12/9/2016	10.10%	2.51%	7.59%
12/15/2016	9.00%	2.52%	6.48%
12/15/2016	9.00%	2.52%	6.48%
12/20/2016	9.75%	2.53%	7.22%
12/22/2016	9.50%	2.54%	6.96%
1/24/2017	9.00%	2.59%	6.41%
2/21/2017	10.55%	2.63%	7.92%
3/1/2017	9.25%	2.65%	6.60%
4/11/2017	9.50%	2.77%	6.73%
4/20/2017	8.70%	2.79%	5.91%
4/28/2017	9.50%	2.82%	6.68%
5/23/2017	9.60%	2.88%	6.72%
6/6/2017	9.70%	2.91%	6.79%
6/22/2017	9.70%	2.94%	6.76%
6/30/2017	9.60%	2.95%	6.65%
7/20/2017	9.55%	2.97%	6.58%
7/31/2017	10.10%	2.98%	7.12%
9/13/2017	9.40%	2.93%	6.47%
9/19/2017	9.70%	2.92%	6.78%
9/22/2017	11.88%	2.92%	8.96%
9/27/2017	10.20%	2.92%	7.28%
10/20/2017	9.60%	2.90%	6.70%
10/26/2017	10.20%	2.90%	7.30%
10/30/2017	10.05%	2.90%	7.15%

[6] Date of Natural Gas Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
12/5/2017	9.50%	2.86%	6.64%
12/7/2017	9.80%	2.85%	6.95%
12/13/2017	9.25%	2.85%	6.40%
12/28/2017	9.50%	2.84%	6.66%
1/31/2018	9.80%	2.83%	6.97%
2/21/2018	9.80%	2.84%	6.96%
2/21/2018	9.80%	2.84%	6.96%
2/28/2018	9.50%	2.85%	6.65%
3/15/2018	9.00%	2.87%	6.13%
3/26/2018	10.19%	2.88%	7.31%
4/26/2018	9.50%	2.91%	6.59%
4/27/2018	9.30%	2.91%	6.39%
5/2/2018	9.50%	2.91%	6.59%
5/3/2018	9.70%	2.91%	6.79%
5/29/2018	9.40%	2.95%	6.45%
6/6/2018	9.80%	2.96%	6.84%
6/14/2018	8.80%	2.97%	5.83%
7/16/2018	9.60%	2.98%	6.62%
7/20/2018	9.40%	2.99%	6.41%
8/24/2018	9.28%	3.02%	6.26%
8/28/2018	10.00%	3.03%	6.97%
9/13/2018	10.00%	3.04%	6.96%
9/14/2018	10.00%	3.05%	6.95%
9/19/2018	9.85%	3.05%	6.80%
9/20/2018	9.80%	3.06%	6.74%
9/26/2018	9.40%	3.06%	6.34%
9/26/2018	10.20%	3.06%	7.14%
9/28/2018	9.50%	3.07%	6.43%
9/28/2018	9.50%	3.07%	6.43%
10/5/2018	9.61%	3.08%	6.53%
10/15/2018	9.80%	3.09%	6.71%
10/26/2018	9.40%	3.11%	6.29%
10/29/2018	9.60%	3.11%	6.49%
11/1/2018	9.87%	3.11%	6.76%
11/8/2018	9.70%	3.12%	6.58%
11/8/2018	9.70%	3.12%	6.58%
12/11/2018	9.70%	3.14%	6.56%
12/12/2018	9.30%	3.14%	6.16%
12/13/2018	9.60%	3.14%	6.46%
12/19/2018	9.30%	3.15%	6.15%
12/21/2018	9.35%	3.15%	6.20%
12/24/2018	9.25%	3.15%	6.10%
12/24/2018	9.25%	3.15%	6.10%
1/4/2019	9.80%	3.14%	6.66%
1/18/2019	9.70%	3.14%	6.56%
3/14/2019	9.00%	3.12%	5.88%
		Average:	4.69%
		Count:	1,117

Expected Earnings Analysis

Company	Ticker	[1] Expected ROE 2022-24	[2] Shares Outstanding 2019	[3] Shares Outstanding 2022-24	[4] % Increase	[5] Adjustment Factor	[6] Adjusted ROE
Atmos Energy Corporation	ATO	10.0%	120.00	145.00	4.84%	1.024	10.24%
Chesapeake Utilities Corporation	CPK	10.0%	17.50	20.00	3.39%	1.017	10.17%
New Jersey Resources Corporation	NJR	11.0%	88.00	89.00	0.28%	1.001	11.02%
Northwest Natural Gas Company	NWN	12.0%	30.00	32.00	1.63%	1.008	12.10%
ONE Gas, Inc.	OGS	10.0%	53.00	55.00	0.93%	1.005	10.05%
South Jersey Industries, Inc.	SJI	12.0%	90.00	98.00	2.15%	1.011	12.13%
Spire Inc.	SR	10.5%	52.00	55.00	1.41%	1.007	10.57%
						Median	10.57%
						Average	10.89%

Notes:

[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals = ([3] / [2])^(1/4)-1
[5] Equals (2 x (1 + [4])) / (2 + [4])
[6] Equals [1] x [5]

Summary of Adjustment Clauses & Alternative Regulation/Incentive Plans

			Adjustment Clauses						Alternative Regulation / Incentive Plans					
Company	Parent	State	Fuel/ Purchased Power	Decoupling (F/P) [1]	Capital Investment [2]	Capital Investment Pre-Tax ROR [3]	Energy Efficiency [4]	Other [5]	Formula-Based Rates	Price Freeze/ Cap	Earnings Sharing/PBR	Formula-Based ROE	Service Quality/ Performance	Merger Savings
Atmos Energy	ATO	Colorado	✓		✓	9.27%	✓							
Atmos Energy	ATO	Kansas	✓	P	✓	9.54%		✓						
Atmos Energy	ATO	Kentucky	✓	P	✓	9.09%	✓				✓			
Atmos Energy	ATO	Louisiana	✓	P	✓	9.61%			✓		✓			✓
Atmos Energy	ATO	Mississippi	✓	P	✓	9.34%	✓	✓	✓			✓	✓	
Atmos Energy	ATO	Tennessee	✓	P	✓	9.03%			✓		✓			
Atmos Energy	ATO	Texas	✓	P	✓	10.01%	✓	✓	✓					
Atmos Energy	ATO	Virginia	✓	P	✓	9.28%								
Chesapeake Utilities	CPK	Delaware	✓					✓						
Chesapeake Utilities	CPK	Maryland	✓	P			✓	✓						
Florida Public Utilities Company	CPK	Florida	✓		✓	8.30%	✓	✓						
New Jersey Natural Gas	NJR	New Jersey	✓	F	✓	8.90%	✓	✓						
Northwest Natural Gas	NWN	Oregon	✓	P	✓	9.54%	✓	✓						
Northwest Natural Gas	NWN	Washington	✓				✓	✓						
Kansas Gas Service	OGS	Kansas	✓	P	✓	8.33%		✓						
Oklahoma Natural Gas	OGS	Oklahoma	✓	P	✓	9.08%	✓	✓	✓		✓			
Texas Gas Service	OGS	Texas	✓	P	✓	8.80%		✓	✓					
Alabama Gas Corporation	SR	Alabama	✓	P	✓	N/A		✓	✓					
Spire Gulf Inc. (Mobile Gas Corporation)	SR	Alabama	✓	P	✓	N/A		✓	✓					
Spire Missouri East	SR	Missouri	✓	P	✓	9.06%		✓						
Spire Missouri West	SR	Missouri	✓	P	✓	9.06%		✓						
Elizabethtown Gas	SJI	New Jersey	✓	P			✓	✓						
South Jersey Gas	SJI	New Jersey	✓	F	✓	8.77%	✓	✓						

Notes:

Note: A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category.

[1] Full or partial decoupling (such as Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs). All full or partial decoupling mechanisms include weather normalization adjustments.

[2] Includes recovery of costs related to infrastructure replacement, system integrity/hardening, and other capital expenditures.

[3] Refllects the Pre-Tax Rate of Return applicable to the capital investment mechanism. Average and median authorized ROE for the proxy group is 10.18% and 9.80%, respectively.

[4] Utility-sponsored conservation, energy efficiency, or other demand side management programs.

[5] Pension expenses, bad debt costs, storm costs, transmission/transportation costs, environmental, regulatory fee, government & franchise fees and taxes, economic development, and low income programs.

Sources: Operating company tariffs; Regulatory Research Associates, *Alternative Regulation/Incentive Plans: A State-by-State Overview* , November 19, 2013; Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview,* September 28, 2018; *Edison Electric Institute, Alternative Regulation for Emerging Utility Challenges: 2015 Update, November 11, 2015* .

Flotation Costs

Two most recent open market common stock issuances per company, if available

Company	Date	Shares Issued	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds Per Share	Total Flotation Costs	Gross Equity Issue Before Costs	Net Proceeds	Flotation Cost Percentage
Southwest Gas Corporation	11/27/2018	3,565,000	$75.50	$2.5481	$600,000	$72.78	$9,683,977	$269,157,500	$259,473,524	3.598%
Atmos Energy Corporation	11/28/2018	7,008,087	$92.75	$0.9769	$1,000,000	$91.63	$7,846,200	$650,000,069	$642,153,869	1.207%
Atmos Energy Corporation	11/28/2017	4,558,404	$88.56	NA	NA	NA	NA	$403,692,258	NA	NA
Chesapeake Utilities Corporation	9/21/2016	960,488	$62.26	$2.3300	$157,000	$59.77	$2,394,937	$59,799,983	$57,405,046	4.005%
Chesapeake Utilities Corporation	11/13/2006	690,345	$30.10	$1.1300	$225,000	$28.64	$1,005,090	$20,779,385	$19,774,295	4.837%
Northwest Natural Gas Company	11/10/2016	1,012,000	$54.63	$2.0500	$250,000	$52.33	$2,324,600	$55,285,560	$52,960,960	4.205%
Northwest Natural Gas Company	3/30/2004	1,290,000	$31.00	$1.0100	$175,000	$29.85	$1,477,900	$39,990,000	$38,512,100	3.696%
South Jersey Industries, Inc.	4/17/2018	12,669,491	$29.50	$1.0325	$700,000	$28.41	$13,781,249	$373,749,985	$359,968,735	3.687%
South Jersey Industries, Inc.	5/10/2016	8,050,000	$26.25	$0.9200	$330,000	$25.29	$7,736,000	$211,312,500	$203,576,500	3.661%
Spire Inc.	5/7/2018	2,300,000	$68.75	$2.1094	$325,000	$66.50	$5,176,574	$158,125,000	$152,948,426	3.274%
Spire Inc.	5/11/2016	2,185,000	$63.05	$2.0491	$300,000	$60.86	$4,777,284	$137,764,250	$132,986,967	3.468%
Mean							$5,620,381	$216,332,408		
									WEIGHTED AVERAGE FLOTATION COSTS:	2.598%

Constant Growth Discounted Cash Flow Model Adjusted for Flotation Costs - 30 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
					Expected Dividend Yield								
Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Current	Adjusted for Flot. Costs	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Value Line Retention Growth	Average Earnings Growth	DCF k(e)	Flotation Adjusted DCF k(e)
Atmos Energy Corporation	ATO	$2.10	$98.52	2.13%	2.21%	2.27%	6.50%	6.40%	7.50%	10.09%	7.62%	9.84%	9.89%
Chesapeake Utilities Corporation	CPK	$1.48	$90.47	1.64%	1.70%	1.75%	6.00%	6.00%	9.00%	10.63%	7.91%	9.61%	9.65%
New Jersey Resources Corporation	NJR	$1.17	$48.00	2.44%	2.50%	2.57%	7.00%	6.00%	2.50%	5.48%	5.25%	7.75%	7.81%
Northwest Natural Gas Company	NWN	$1.90	$63.54	2.99%	3.14%	3.22%	4.30%	4.00%	25.50%	6.42%	10.06%	13.20%	13.28%
ONE Gas, Inc.	OGS	$2.00	$85.41	2.34%	2.42%	2.48%	5.90%	5.00%	9.00%	5.27%	6.29%	8.71%	8.77%
South Jersey Industries, Inc.	SJI	$1.15	$30.53	3.77%	3.90%	4.00%	5.90%	5.90%	9.50%	7.05%	7.09%	10.99%	11.09%
Spire Inc.	SR	$2.37	$78.49	3.02%	3.09%	3.17%	3.90%	2.42%	5.50%	5.85%	4.42%	7.50%	7.59%
PROXY GROUP MEAN												9.66%	9.73%

DCF Result Adjusted For Flotation Costs:	9.73%	
DCF Result Unadjusted For Flotation Costs:	9.66%	
Difference (Flotation Cost Adjustment):	$\boxed{0.07\%}$	[13]

Notes:
The proxy group DCF result is adjusted for flotation costs by dividing each company's expected dividend yield by (1 - flotation cost). The flotation cost adjustment is derived as the difference between the unadjusted DCF result and the DCF result adjusted for flotation costs.
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [10])
[5] Equals [4] / (1 - 2.598%)
[6] Source: Zacks
[7] Source: Yahoo! Finance
[8] Source: Value Line
[9] Source: Exhibit RBH-3, Value Line
[10] Equals Average([6], [7], [8], [9])
[11] Equals [4] + [10]
[12] Equals [5] + [10]
[13] Equals average [12] - average [11]

Calculation of the Fair Value Rate Base

Rate Base Estimate	Amount	Weighting	Weighted Amount	
Original Cost Rate Base (OCRB)	$ 1,991,543,072	50%	$ 995,771,536	[1]
RCND Rate Base	3,234,113,450	50%	1,617,056,725	[2]
Fair Value Rate Base (FVRB)			$ 2,612,828,261	[3]
Appreciation Above OCRB			$ 621,285,189	[4]
FV / OCRB Multiple			1.3120 x	

Calculation of the Fair Value Rate of Return

Capital	Amount	Percent	Cost Rate		Weighted Cost Rate
Capital Structure OCRB					
Long-Term Debt	$ 973,864,562	48.90%	4.86%	[5]	2.38%
Common Equity	1,017,678,510	51.10%	10.30%	[6]	5.26%
Total Capital OCRB	$ 1,991,543,072	100.00%			7.64%
Capital Structure FVRB					
Long-Term Debt	$ 973,864,562	37.27%	4.86%		1.81%
Common Equity	1,017,678,510	38.95%	10.30%		4.01%
Appreciation Above OCRB	621,285,189	23.78%	0.66%	[7]	0.16%
Total Capital FVRB	$ 2,612,828,261	100.00%			5.98%

Notes:
[1] Direct Testimony of Randi L. Cunningham
[2] Direct Testimony of Randi L. Cunningham
[3] Equals [1] + [2]
[4] Equals [3] - OCRB
[5] Direct Testimony of Theodore K. Wood
[6] Recommended ROE on OCRB
[7] 50 percent of real risk-free rate of return derived on page 2 of this Exhibit

Long-Term Inflation Rate Estimate

Description	Value
Long-Term Nominal Treasury Rate [1]	3.65%
Long-Term Expected Inflation Rate [2]	2.30%
Real Risk-Free Rate of Return [3]	1.32%

Notes:

[1] Average of the near term and long term projected Nominal 30-year Treasury rate. For the short-term projected yield, see Blue Chip Financial Forecasts, Vol. 38, No. 3, March 1, 2019, at 2; for the long-term projected yield, see Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14

[2] Average of the EIA Annual Energy Outlook Rate of Change in CPI from 2018-2050 and Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14

[3] Real Risk-Free Rate = [(1 + Nominal Rate) / (1 + Inflation Rate)] - 1

Credit Ratings - Proxy Group Results

Line No.	Symbol	Company	Moody's	Numerical Weight	S&P	Numerical Weight
	(a)	(b)	(c)	(d)	(e)	(f)
1	ATO	Atmos Energy Corp.	A2	6	A	6
2	CPK	Chesapeake Utilities Corp.				
3	NJR	New Jersey Resources Corp.	Aa2	3	BBB+	8
4	NWN	Northwest Natural Gas	A3	7	A+	5
5	OGS	ONE Gas Inc.	A2	6	A	6
6	SJI	South Jersey Industries, Inc.	A2	6	BBB	9
7	SR	Spire Inc.[1]	A1	5	A-	7
8		Proxy Group Average	A2	6	A-	7
9	SWX	Southwest Gas Corporation	A3	7	BBB+	8

Note:
[1] Based on the primary utility subsidiary Spire Missouri

Legend

Moody's Bond Rating	S&P Bond Rating	Numerical Weight
Aaa	AAA	1
Aa1	AA+	2
Aa2	AA	3
Aa3	AA-	4
A1	A+	5
A2	A	6
A3	A-	7
Baa1	BBB+	8
Baa2	BBB	9
Baa3	BBB-	10
Ba1	BB+	11
Ba2	BB	12
Ba3	BB-	13

Moody's Regulatory Framework - Proxy Group Results

	ATO	CPK	NJR	NWN	OGS	SJI	SR	Average	SWX
Factor 1: Regulatory Framework (25%)									
Legislative and Judicial Underpinnings of Regulatory Framework	A		A	A	A	A	A		A
Consistency and Predictability of Regulation	Aa		Aa	A	A	Aa	A		A
Factor 2: Ability to Recover Costs and Earn Returns (25%)									
Timeliness of Recovery of Operating and Capital Costs	A		A	Aa	A	A	A		A
Sufficiency of Rates and Returns	Baa		A	A	Baa	A	A		Baa
Factor 1: Regulatory Framework (25%)									
Legislative and Judicial Underpinnings of Regulatory Framework	2.00		2.00	2.00	2.00	2.00	2.00	2.00	2.00
Consistency and Predictability of Regulation	3.00		3.00	2.00	2.00	3.00	2.00	2.50	2.00
Factor 2: Ability to Recover Costs and Earn Returns (25%)									
Timeliness of Recovery of Operating and Capital Costs	2.00		2.00	3.00	2.00	2.00	2.00	2.17	2.00
Sufficiency of Rates and Returns	1.00		2.00	2.00	1.00	2.00	2.00	1.67	1.00
Average	2.00		2.25	2.25	1.75	2.25	2.00	2.08	1.75

Note:
Source: Moody's Investors Service Credit Opinions Publications

Scale	
Aaa	4
Aa	3
A	2
Baa	1

Southwest Gas Corporation

DOCKET NO. G-01551A-19-0055

2019 General Rate Case

Supporting Schedules

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May 1, 2019

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SCHEDULE A

SOUTHWEST GAS CORPORATION
ARIZONA
INCREASE IN GROSS REVENUE REQUIREMENT
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Reference	Original Cost	Reproduction Cost New Less Depreciation	Fair Value	Line No.
	(a)	(b)	(c)	(d)	(e) [(c) + (d)] / 2	
1	Adjusted Rate Base	Sch B-1, Sh 1, Ln 15	$ 1,991,543,072	$ 3,234,113,450	$ 2,612,828,261	1
2	Adjusted Operating Income	Sch C-1, Sh 1, Ln 19(e)	113,509,228	113,509,228	113,509,228	2
3	Current Rate of Return	Ln 2 / Ln 1	5.70%	3.51%	4.34%	3
4	Required Operating Income	Sch A-1, Sh 2, Ln 19(g)	$ 156,251,187	$ 156,251,187	$ 156,251,187	4
5	Required Rate of Return	Ln 4 / Ln 1	7.85%	4.83%	5.98%	5
6	Operating Income Deficiency	Ln 4 - Ln 2			$ 42,741,958	6
7	Gross Revenue Conversion Factor	Sch C-3, Sh 1, Ln 8(c)			1.3336	7
8	Increase in Gross Revenue Requirements	Ln 6 * Ln 7			$ 57,001,443	8

Note: Spread of revenue increase by customer classification is shown on Schedule A-1, Sheet 3.

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF THE OVERALL RESULTS OF OPERATIONS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Reference	Recorded 1/31/2019	Adjustments	Adjusted 1/31/2019	Deficiency	Adjusted for Deficiency	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
			Sch C-1, Sh 1, Col (c)	Sch C-1, Sh 1, Col (d)	(c) + (d)		(e) + (f)	
1	Operating Revenue		$ 701,861,440	$ (183,643,076)	$ 518,218,363	$ 57,001,443	$ 575,219,806	1
2	Gas Cost		201,173,630	(201,173,630)	0	0	0	2
3	Operating Margin	Ln 1 - Ln 2	$ 500,687,809	$ 17,530,554	$ 518,218,363	$ 57,001,443	$ 575,219,806	3
	Operating Expenses							
4	Other Gas Costs		$ 1,267,230	$ 90,917	$ 1,358,147	$ 0	$ 1,358,147	4
5	Storage		0	1,470,088	1,470,088	0	1,470,088	5
6	Distribution		106,965,636	1,996,392	108,962,028	0	108,962,028	6
7	Customer Accounts		24,864,595	783,894	25,648,489	110,019	25,758,507	7
8	Customer Service & Info.		424,773	(45,406)	379,366	0	379,366	8
9	Sales		12,629	(5,050)	7,579	0	7,579	9
	Administrative & General							
10	Direct		5,152,768	874,447	6,027,215	0	6,027,215	10
11	System Allocable		88,354,236	(572,485)	87,781,751	0	87,781,751	11
	Depreciation & Amortization							
12	Direct		90,541,589	10,835,680	101,377,269	0	101,377,269	12
13	System Allocable		11,134,978	3,544,503	14,679,481	0	14,679,481	13
14	Regulatory Amortizations		6,769,642	(10,198,917)	(3,429,275)	0	(3,429,275)	14
15	Taxes Other Than Income		42,244,348	15,911,411	58,155,759	0	58,155,759	15
16	Interest on Customer Deposits		2,180,878	(1,222,444)	958,434	0	958,434	16
17	Income Taxes		19,091,352	(17,758,548)	1,332,804	14,149,466	15,482,271	17
18	Total Operating Expenses	Sum Lns 4-17	$ 399,004,654	$ 5,704,481	$ 404,709,135	$ 14,259,485	$ 418,968,620	18
19	Net Operating Income	Ln 3 - Ln 18	$ 101,683,155	$ 11,826,073	$ 113,509,228	$ 42,741,958	$ 156,251,187	19
	Rate Base							
	Gross Plant in Service							
20	Direct	Sch B-1	$ 3,704,575,635	$ 179,464,406	$ 3,884,040,042	$ 1,117,314,537	$ 5,001,354,579	20
21	System Allocable	Sch B-1	180,871,777	34,281,176	215,152,953	5,670,419	220,823,372	21
22	Total Gross Plant in Service	Ln 20 + Ln 21	$ 3,885,447,413	$ 213,745,582	$ 4,099,192,995	$ 1,122,984,955	$ 5,222,177,950	22
	Accumulated Depreciation							
23	Direct	Sch B-1	$ 1,416,558,591	$ (104,738)	$ 1,416,453,853	$ 428,925,164	$ 1,845,379,017	23
24	System Allocable	Sch B-1	123,855,015	(527,791)	123,327,224	1,870,843	125,198,067	24
25	Total Accumulated Depreciatio	Ln 23 + Ln 24	$ 1,540,413,606	$ (632,529)	$ 1,539,781,077	$ 430,796,007	$ 1,970,577,084	25
26	Net Plant in Service	Ln 22 - Ln 25	$ 2,345,033,807	$ 214,378,112	$ 2,559,411,918	$ 692,188,948	$ 3,251,600,866	26
	Other Rate Base							
	Allowance for Working Capital							
27	Cash Working Capital	Sch B-1, Sh 2, Ln 8	$ (10,297,032)	$ 0	$ (10,297,032)	$ 0	$ (10,297,032)	27
28	Materials and Supplies	Sch B-1, Sh 2, Ln 9	34,013,908	2,800,000	36,813,908	0	36,813,908	28
29	Prepayments	Sch B-1, Sh 2, Ln 10	7,721,011	0	7,721,011	0	7,721,011	29
30	Customer Deposits	Sch B-1, Sh 2, Ln 11	(36,862,844)	0	(36,862,844)	0	(36,862,844)	30
31	Customer Advances	Sch B-1, Sh 2, Ln 12	(41,613,406)	0	(41,613,406)	0	(41,613,406)	31
32	Deferred Taxes	Sch B-1, Sh 2, Ln 13	(525,148,656)	1,518,173	(523,630,483)	(70,903,759)	(594,534,243)	32
33	Total Other Rate Base	Sum Lns 27-32	$ (572,187,019)	$ 4,318,173	$ (567,868,846)	$ (70,903,759)	$ (638,772,605)	33
34	Total Rate Base	Ln 26 + Ln 33	$ 1,772,846,788	$ 218,696,285	$ 1,991,543,072	$ 621,285,189	$ 2,612,828,261	34
35	Rate of Return	Ln 19 / Ln 34	5.74%		5.70%		5.98%	35

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SPREAD OF REVENUE INCREASE BY CUSTOMER CLASS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Present Schedule Number	Increase/(Decrease) [1] Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	
	Residential Service				
1	Single-Family Residential Gas Service	G-5	$ 41,294,573	9.44%	1
2	Multi-Family Residential Gas Service	G-6	1,379,657	12.29%	2
3	Single-Family Low Income Residential Gas Service	G-10	1,074,886	7.19%	3
4	Multi-Family Low Income Residential Gas Service	G-11	98,372	10.26%	4
5	Special Residential Gas Service for Air Conditioning	G-15	16,358	27.22%	5
6	Master-Metered Mobile Home Park Gas Service	G-20	52,577	4.21%	6
	General Gas Service				
7	Small	G-25(S)	838,183	7.62%	7
8	Medium	G-25(M)	4,199,463	10.01%	8
9	Large-1	G-25(L1)	3,713,221	4.20%	9
10	Large-2	G-25(L2)	1,322,057	5.56%	10
11	Transportation Eligible	G-25(TE)	2,391,970	6.64%	11
12	Optional Gas Service	G-30	0	0.00%	12
13	Air Conditioning Gas Service	G-40	3,398	2.77%	13
14	Street Lighting Gas Service	G-45	1,606	13.28%	14
	Gas Service for Compression on Customer's Premises				
15	Residential	G-55 (R)	461	2.59%	15
16	Small	G-55 (S)	428	2.87%	16
17	Large	G-55 (L)	213,316	6.01%	17
18	Electric Generation Gas Service	G-60	208,018	6.63%	18
19	Small Essential Agriculture User Gas Service	G-75	80,706	3.49%	19
20	Natural Gas Engine Gas Service	G-80	112,449	1.97%	20
21	Total Sales and Full Margin Transportation		$ 57,001,699	8.31%	21
22	Potential Bypass/Standby Gas Service	B-1	0	0.00%	22
23	Other Operating Revenue		0	0.00%	23
24	Total Arizona Revenue		$ 57,001,699	8.15%	24

[1] Schedule H-1, Sheet 1.

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY RESULTS OF OPERATIONS

Line No.	Description	Prior Years: Year Ended 2017	Prior Years: Year Ended 2018	Test Year: Actual 01/31/19	Test Year: Adjusted 01/31/19	Projected Year: Present Rates 01/31/20	Projected Year: Proposed Rates 01/31/20	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
		Sch E-2, Sh 1	Sch E-2, Sh 1	Sch E-2, Sh 1	Sch A-1, Sh 2 Sch C-1, Sh 16	Sch A-1, Sh 2 Sch F-1, Sh 1	Sch A-1, Sh 2 Sch F-1, Sh 1	
1	Operating Revenues	$ 698,283,506	$ 703,154,972	$ 701,861,439	$ 719,391,994	$ 706,868,318	$ 776,393,437	1
2	Operating Expenses and Taxes	600,070,532	600,533,882	600,178,284	605,882,765	615,075,791	620,142,250	2
3	Net Operating Income	$ 98,212,974	$ 102,621,090	$ 101,683,155	$ 113,509,228	$ 91,792,526	$ 156,251,187	3
4	Other Income and Deductions	0	0	0	0	0	0	4
5	Interest Expense	35,887,107	43,133,574	42,132,413	47,329,818	42,132,413	47,329,818	5
6	Net Income	$ 62,325,867	$ 59,487,516	$ 59,550,742	$ 66,179,411	$ 49,660,113	$ 108,921,369	6

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
SUMMARY RESULTS OF OPERATIONS [1]

Line No.	Description	Prior Years: Year Ended 2017	Prior Years: Year Ended 2018	Test Year: 12 Months Ended 1/31/2019	Line No.
	(a)	(b)	(c)	(d)	
		Sch E-2, Sh 2	Sch E-2, Sh 2	Sch E-2, Sh 2	
1	Gross Revenues	$ 1,302,308,138	$ 1,357,727,493	$ 1,369,234,730	1
2	Revenue Deductions & Operating Expenses	1,094,097,856	1,137,078,410	1,145,925,001	2
3	Operating Income	$ 208,210,282	$ 220,649,084	$ 223,309,728	3
4	Other Income and (Deductions)	213,227,113	366,286	961,021	4
5	Income Before Interest Deductions	$ 421,437,395	$ 221,015,370	$ 224,270,749	5
6	Interest Expense	$ 72,443,727	$ 85,437,138	$ 86,970,616	6
7	Allowance for Debt Funds Used During Construction	(1,666,170)	(3,263,782)	(3,420,448)	7
8	Net Interest Expense	$ 70,777,557	$ 82,173,356	$ 83,550,168	8
9	Net Income	$ 350,659,838	$ 138,842,014	$ 140,720,581	9
10	Preferred and Preference Dividend Requirements	0	0	0	10
11	Net Income Applicable to Common Stock	$ 350,659,838	$ 138,842,014	$ 140,720,581	11
12	Weighted Average Shares of Common Stock Outstanding	47,965,243	49,418,549	49,838,144	12
13	Earnings per Common Share	$ 7.31	$ 2.81	$ 2.82	13
14	Dividends Paid per Common Share	1.98	2.08	2.11	14
15	Dividend Pay-Out Ratio	27.08%	74.03%	74.55%	15
16	Return on Average Invested Capital	15.45%	5.89%	7.33%	16
17	Return on Year-End Invested Capital	12.42%	7.34%	7.22%	17
18	Return on Average Common Equity	15.45%	5.89%	7.33%	18
19	Return on Year-End Common Equity	12.42%	7.34%	7.22%	19
20	Times Bond Interest Earned- Before Income Taxes	8.42	4.13	4.11	20
21	Times Total Interest and Preferred Dividend Earned - After Income Taxes	2.41	1.81	2.68	21

[1] In this proceeding, the Company is requesting rate relief for the Arizona rate jurisdiction of its system only. Projections for the total Company's financial position are not compiled or available.

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
SUMMARY OF CAPITAL STRUCTURE

Line No.	Description (a)	Prior Years At 12/31/2017 (b)	Prior Years At 12/31/2018 (c)	Test Year At 01/31/2019 (d)	Projected At 01/31/2020 [1] (e)	Line No.
	Capital Amounts					
1	Short-Term Debt	$ 191,000,000	$ 152,000,000	$ 169,000,000	$ 167,000,000	1
2	Long-Term Debt[2]	1,521,031,253	1,818,669,292	1,800,299,986	2,101,499,731	2
3	Total Debt	1,712,031,253	1,970,669,292	1,969,299,986	2,268,499,731	3
4	Preferred Equity	-	-	-	-	4
5	Common Equity[3]	1,657,072,174	1,831,508,420	1,881,310,331	2,120,630,331	5
6	Total Capital	$ 3,369,103,427	$ 3,802,177,712	$ 3,850,610,317	$ 4,389,130,062	6
	Capitalization Ratios					
7	Short-Term Debt	5.67%	4.00%	4.39%	3.80%	7
8	Long-Term Debt	45.15%	47.83%	46.75%	47.88%	8
9	Total Debt	50.82%	51.83%	51.14%	51.68%	9
10	Preferred Equity	0.00%	0.00%	0.00%	0.00%	10
11	Common Equity	49.18%	48.17%	48.86%	48.32%	11
12	Total	100.00%	100.00%	100.00%	100.00%	12
	Weighted Cost of Capital					
13	Short-Term Debt	0.14%	0.14%	0.16%	0.14%	13
14	Long-Term Debt	2.09%	2.21%	2.15%	2.20%	14
15	Preferred Equity	0.00%	0.00%	0.00%	0.00%	15
16	Common Equity	4.67%	4.58%	5.03%	4.98%	16
17	Total Weighted Cost of Capital	6.91%	6.92%	7.33%	7.33%	17

[1] Estimated
[2] Includes current maturities of long-term debt
[3] Common equity does not reflect accumulated other comprehensive income balances

SOUTHWEST GAS CORPORATION
ARIZONA
HISTORICAL AND PROJECTED
CONSTRUCTION EXPENDITURES, PLANT PLACED IN SERVICE, AND GROSS PLANT

		Actual			Projected			
Line No.	Description	Year Ended 2017	Year Ended 2018	Test Year Ended 1/31/2019	Year Ending 1/31/2020	Year Ending 1/30/2021	Year Ending 1/30/2022	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
		Company Records	Company Records	Company Records	Company Records	Company Records	Company Records	
	Construction Expenditures							
1	Arizona Direct	$ 275,921,621	$ 341,696,553	$ 348,102,935	$ 309,373,320	$ 309,670,496	$ 309,670,496	1
2	System Allocable [1]	9,202,188	8,777,783	7,392,419	58,777,942	46,874,832	46,874,832	2
3	Total Construction Expenditures	$ 285,123,809	$ 350,474,336	$ 355,495,353	$ 368,151,262	$ 356,545,328	$ 356,545,328	3
	Net Plant Placed in Service							
4	Arizona Direct	$ 233,667,311	$ 299,776,830	$ 17,258,782	$ 269,373,320	$ 269,670,496	$ 269,670,496	4
5	System Allocable [1]	5,694,843	2,872,493	1,126,772	53,210,173	41,307,062	41,307,062	5
6	Total Net Plant Placed in Service	$ 239,362,154	$ 302,649,323	$ 18,385,554	$ 322,583,493	$ 310,977,558	$ 310,977,558	6
	Gross Utility Plant in Service							
7	Arizona Direct	$ 3,387,540,023	$ 3,687,316,853	$ 3,704,575,635	$ 3,973,948,955	$ 4,243,619,451	$ 4,513,289,947	7
8	System Allocable [1]	176,872,513	179,745,006	180,871,777	234,081,950	275,389,013	316,696,075	8
9	Total Gross Utility Plant in Service	$ 3,564,412,536	$ 3,867,061,859	$ 3,885,447,413	$ 4,208,030,906	$ 4,519,008,464	$ 4,829,986,022	9

[1] After 4-Factor allocation to AZ. Schedule C-1,Sheet 17, Ln 9(c)

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
SUMMARY STATEMENT OF CASH FLOWS
CHANGES IN FINANCIAL POSITION
($ THOUSANDS)

Line No.	Description	Prior Years: Year Ended 2017	Prior Years: Year Ended 2018	Test Year: 12 Months Ended 1/31/2019	Projected Year, Year Ended 1/31/20: At Present Rates	Projected Year, Year Ended 1/31/20: At Proposed Rates	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
		Sch E-3, Sh 1	Sch E-3, Sh 1	Sch E-3, Sh 1	Sch F-2, Sh 1	Sch F-2, Sh 1	
1	Cash Flows from Operating Activities	$ 306,640	$ 382,513	$ 387,457	$ 397,205	$ 434,949	1
2	Cash Flows from Investing Activities	(554,850)	(669,384)	(667,749)	(309,601)	(309,601)	2
3	Cash Flows from Financing Activities	267,090	280,906	266,866	390,017	390,017	3
4	Increase (Decrease) in Cash and Cash Equivalents	$ 18,880	$ (5,965)	$ (13,426)	$ 477,621	$ 515,365	4

SCHEDULE B

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF ADJUSTED ORIGINAL COST AND RCND RATE BASE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Reference	Adjusted Original Cost Rate Base	Adjusted RCND Rate Base	Fair Value [1] Rate Base	Line No.
	(a)	(b)	(c)	(d)	(e)	
			Sch B-1, Sh 2, Col (e)	Net Plant: Sch B-3, Sh 1, Col (e)	[(c) + (d)] / 2	
	Gross Plant in Service					
1	Direct		$ 3,884,040,042	$ 6,118,669,115	$ 5,001,354,579	1
2	System Allocable		215,152,953	226,493,790	220,823,372	2
3	Total Gross Plant in Service	Ln 1 + Ln 2	$ 4,099,192,995	$ 6,345,162,906	$ 5,222,177,950	3
	Accumulated Depreciation					
4	Direct		$ 1,416,453,853	$ 2,274,304,182	$ 1,845,379,017	4
5	System Allocable		123,327,224	127,068,910	125,198,067	5
6	Total Accumulated Depreciation	Ln 4 + Ln 5	$ 1,539,781,077	$ 2,401,373,091	$ 1,970,577,084	6
7	Net Plant in Service	Ln 3 - Ln 6	$ 2,559,411,918	$ 3,943,789,814	$ 3,251,600,866	7
	Other Rate Base					
	Allowance for Working Capital					
8	Cash Working Capital		$ (10,297,032)	$ (10,297,032)	$ (10,297,032)	8
9	Materials and Supplies		36,813,908	36,813,908	36,813,908	9
10	Prepayments		7,721,011	7,721,011	7,721,011	10
11	Customer Deposits		(36,862,844)	(36,862,844)	(36,862,844)	11
12	Customer Advances		(41,613,406)	(41,613,406)	(41,613,406)	12
13	Deferred Taxes		(523,630,483)	(665,438,002)	(594,534,243)	13
14	Total Other Rate Base	Sum Lns 8-13	$ (567,868,846)	$ (709,676,365)	$ (638,772,605)	14
15	Total Rate Base	Ln 7 + Ln 14	$ 1,991,543,072	$ 3,234,113,450	$ 2,612,828,261	15
			Sch A-1, Sh 1, Ln 1(c)	Sch A-1, Sh 1, Ln 1(d)	Sch A-1, Sh 1, Ln 1(e)	

[1] 50/50 weighting of original cost rate base and reproduction cost new less depreciation (RCND) rate base.

SOUTHWEST GAS CORPORATION
ARIZONA
RECORDED RATE BASE, AS ADJUSTED
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Reference	Recorded at 1/31/2019	Adjustments	Adjusted at 1/31/2019	Line No.
	(a)	(b)	(c)	(d)	(e)	
					(c) + (d)	
	Gross Plant in Service					
1	Direct	Sch B-2, Sh 1, Ln 5	$ 3,704,575,635	$ 179,464,406	$ 3,884,040,042	1
2	System Allocable	Sch B-2, Sh 1, Ln 20	180,871,777	34,281,176	215,152,953	2
3	Total Gross Plant in Service	Ln 1 + Ln 2	$ 3,885,447,413	$ 213,745,582	$ 4,099,192,995	3
	Accumulated Depreciation					
4	Direct	Sch B-2, Sh 1, Ln 10	$ 1,416,558,591	$ (104,738)	$ 1,416,453,853	4
5	System Allocable	Sch B-2, Sh 1, Ln 21	123,855,015	(527,791)	123,327,224	5
6	Total Accumulated Depreciation	Ln 4 + Ln 5	$ 1,540,413,606	$ (632,529)	$ 1,539,781,077	6
7	Net Plant in Service	Ln 3 - Ln 6	$ 2,345,033,807	$ 214,378,112	$ 2,559,411,918	7
	Other Rate Base					
	Allowance for Working Capital					
8	Cash Working Capital	Sch B-5, Sh 1	$ (10,297,032)	$ 0	$ (10,297,032)	8
9	Materials and Supplies	Sch B-5, Sh 1	34,013,908	2,800,000	36,813,908	9
10	Prepayments	Sch B-5, Sh 1	7,721,011	0	7,721,011	10
11	Customer Deposits	Sch B-6, Sh 1	(36,862,844)	0	(36,862,844)	11
12	Customer Advances	Sch B-6, Sh 2	(41,613,406)	0	(41,613,406)	12
13	Deferred Taxes	Sch B-6, Sh 3	(525,148,656)	1,518,173	(523,630,483)	13
14	Total Other Rate Base	Sum Lns 8-13	$ (572,187,019)	$ 4,318,173	$ (567,868,846)	14
15	Total Rate Base	Ln 7 + Ln 14	$ 1,772,846,787	$ 218,696,285	$ 1,991,543,072	15
			Sch A-1, Sh 2, Col (c)		Sch B-1, Sh 1, Col (c)	

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF ORIGINAL COST OF GAS PLANT BY FUNCTION
AT JANUARY 31, 2019
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description	Reference	Recorded at 1/31/2019	Adjustments	Adjusted at 1/31/2019	Allocation of System Allocable Plant	Adjusted after Allocation at 1/31/2019	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
			WP B-2, Sh 1, 3, 5, 7 Col (c)	WP B-2, Sh 1, 3, 5, 7 Col (d)	(c) + (d)	Lns 12-17(e) * Ln 19	(e) + (f)	
	Direct Gross Plant in Service (GPIS)							
1	Intangible Plant		$ 4,219,850	$ 0	$ 4,219,850	$ 148,564,500	$ 152,784,350	1
2	Storage Plant		1,772,673	76,200,000	77,972,673	0	77,972,673	2
3	Distribution Plant		3,532,384,830	80,980,126	3,613,364,956	0	3,613,364,956	3
4	General Plant		166,198,282	22,284,281	188,482,563	66,588,453	255,071,016	4
5	Total Direct Gross Plant in Service	Sum Lns 1-4	$ 3,704,575,635	$ 179,464,406	$ 3,884,040,042	$ 215,152,953	$ 4,099,192,995	5
	Direct Accumulated Depreciation							
6	Intangible Plant		$ 3,009,220	$ 0	$ 3,009,220	$ 107,824,595	$ 110,833,815	6
7	Storage Plant		0	0	0	0	0	7
8	Distribution Plant		1,358,231,289	0	1,358,231,289	0	1,358,231,289	8
9	General Plant		55,318,083	(104,738)	55,213,345	15,502,628	70,715,973	9
10	Total Direct Accumulated Depreciation	Sum Lns 6-9	$ 1,416,558,591	$ (104,738)	$ 1,416,453,853	$ 123,327,224	$ 1,539,781,077	10
11	Total Direct Net Plant in Service	Ln 5 - Ln 10	$ 2,288,017,044	$ 179,569,145	$ 2,467,586,189	$ 91,825,730	$ 2,559,411,918	11
			Sch B-1, Sh 2, Col (c)	Sch B-1, Sh 2, Col (d)			Sch B-1, Sh 2, Col (e)	
	System Allocable GPIS							
12	Intangible Plant		$ 237,589,747	$ 29,239,725	$ 266,829,471			12
13	General Plant		87,265,254	32,331,028	119,596,281			13
14	Total System Allocable GPIS	Ln 12 + Ln 13	$ 324,855,000	$ 61,570,752	$ 386,425,753			14
	System Allocable Accumulated Depreciation							
15	Intangible Plant		$ 193,658,510	$ 0	$ 193,658,510			15
16	General Plant		28,791,456	(947,940)	27,843,517			16
17	Total Sys. Alloc. Accumulated Depreciation	Ln 15 + Ln 16	$ 222,449,966	$ (947,940)	$ 221,502,026			17
18	Total System Allocable Net Plant in Service	Ln 14 - Ln 17	$ 102,405,034	$ 62,518,692	$ 164,923,726			18
19	AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)	55.68%	55.68%	55.68%			19
20	Sys. Alloc. GPIS Allocated to AZ	Ln 14 * Ln 19	$ 180,871,777	$ 34,281,176	$ 215,152,953			20
21	Sys. Alloc. Accum. Depreciation Allocated to AZ	Ln 17 * Ln 19	123,855,015	(527,791)	123,327,224			21
22	System Allocable Net Plant Allocated to AZ	Ln 20 - Ln 21	$ 57,016,763	$ 34,808,967	$ 91,825,730			22

SOUTHWEST GAS CORPORATION
ARIZONA
POST-TEST YEAR PLANT
ADJUSTMENT NO. 17

Line No.	Description	Reference	Account Number	Amount	Line No.
	(a)	(b)	(c)	(d)	
	Distribution Plant				
1	Land and Land Rights	n/a	374.1	$ 0	1
2	Mains	WP B-2, Adj. 17, Sh 2, Col (d)	376	58,770,958	2
3	Measuring and Reg. Stations	WP B-2, Adj. 17, Sh 2, Col (e)	378	1,190,887	3
4	Services	WP B-2, Adj. 17, Sh 2, Col (f)	380	21,018,281	4
5	Industrial Measuring and Reg. Sta.	n/a	385	0	5
6	Total Distribution Plant	Sum Lns 1-5		$ 80,980,126	6
	General Plant				
7	Structures and Improv - Co. Owned	WP B-2, Adj. 17, Sh 2, Col (g)	390.1	$ 13,745,000	7
8	Office Furniture and Fixtures	WP B-2, Adj. 17, Sh 2, Col (h)	391	575,000	8
9	Computer Software and Hardware	WP B-2, Adj. 17, Sh 2, Col (i)	391.1	2,634,235	9
10	Transportation Equipment - Light	n/a	392.11	0	10
11	Stores Equipment	n/a	393	0	11
12	Tool, Shop, and Garage Equip.	WP B-2, Adj. 17, Sh 2, Col (j)	394	4,375,650	12
13	Communication Equipment	WP B-2, Adj. 17, Sh 2, Col (k)	397	1,134,000	13
14	Misc. Equipment	WP B-2, Adj. 17, Sh 2, Col (l)	398	50,000	14
15	Total General Plant	Sum Lns 7-14		$ 22,513,885	15
16	Total Arizona	Ln 6 + Ln 15		$ 103,494,011	16
				Sch C-2, Sh 2, Col (h)	

Explanation: to include direct Arizona non-revenue producing plant projects
with an in-service date by July 31, 2019

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
POST-TEST YEAR PLANT
ADJUSTMENT NO. 17

Line No.	Description	Reference	Account Number	Amount	Line No.
	(a)	(b)	(c)	(d)	
	Intangible Plant				
1	Miscellaneous Intangible	WP B-2, Adj. 17, Sh 3, Col (e)	303	$ 29,239,725	1
2	Total Intangible Plant	Ln 1		$ 29,239,725	2
	General Plant				
3	Land and Land Rights	WP B-2, Adj. 17, Sh 4, Col (d)	389.0	$ 2,007,241	3
4	Structures and Improv - Co. Owned	WP B-2, Adj. 17, Sh 4, Col (e)	390.1	18,806,237	4
5	Structures and Improv - Leasehold	WP B-2, Adj. 17, Sh 4, Col (f)	390.2	1,850,000	5
6	Office Furniture and Fixtures	WP B-2, Adj. 17, Sh 4, Col (g)	391	1,000,000	6
7	Computer Software and Hardware	WP B-2, Adj. 17, Sh 4, Col (h)	391.1	5,803,640	7
8	Transportation Equip - Light	WP B-2, Adj. 17, Sh 4, Col (i)	392.11	1,621,360	8
9	Laboratory Equipment	WP B-2, Adj. 17, Sh 4, Col (j)	395	150,000	9
10	Communication Equipment	WP B-2, Adj. 17, Sh 4, Col (k)	397	1,438,000	10
11	Miscellaneous Equipment	WP B-2, Adj. 17, Sh 4, Col (l)	398	1,729,740	11
12	Total General Plant	Sum Lns 3-11		$ 34,406,219	12
13	Total System Allocable Plant	Ln 2 + Ln 12		$ 63,645,943	13
14	AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)		55.68%	14
15	Amount Allocated to AZ	Ln 13 * Ln 14		$ 35,436,594	15
				Sch C-2, Sh 2, Col (h)	

Explanation: to include estimated System Allocable general plant additions
with an in-service date by July 31, 2019 and Account 303 additions through December 31, 2019.

SOUTHWEST GAS CORPORATION
ARIZONA
LIQUIFIED NATURAL GAS (LNG) STORAGE FACILITY
ADJUSTMENT NO. 18

Line No.	Description	Account Number		Estimated Amount	Line No.
	(a)	(b)		(c)	
1	Land	360	$	0	1
2	Structures and Improvements	361		76,200,000	2
3	Liquefaction Equipment	363.1		[1]	3
4	Vaporizing Equipment	363.2		[1]	4
5	Compressor Equipment	363.3		[1]	5
6	Other Equipment	363.5		[1]	6
7	Total Gas Plant in Service		$	76,200,000	7
8	LNG Inventory [2]	164.2	$	2,800,000	8
	Incremental O&M				
9	Labor [3]	Various	$	642,214	9
10	Labor Loading	Various		310,449	10
11	Other O&M	Various		517,425	11
12	Total O&M		$	1,470,088	12
				Sch C-2, Sh 2, Col (i)	

Explanation: to include the plant, inventory and annualized incremental O&M related to the new LNG storage facility expected to be placed into service during the third quarter of 2019.

[1] The LNG facility was bid as a lump sum. When the various assets are unitized, the amounts in the individual FERC accounts will be known. All have the same depreciation rate. The land was included in the test year recorded amount.
[2] See footnote [1] in Schedule B-5, M&S.
[3] Total of eight incremental employees, two were on the payroll at the end of the test year.

SOUTHWEST GAS CORPORATION
ARIZONA
DEFERRED TAXES ADJUSTMENT
ADJUSTMENT NO. 19

Line No.	Description	Reference	AZ Direct	System Allocable	Line No.
	(a)	(b)	(c)	(d)	
			Company Records	Company Records	
	Tie Deferred Taxes to Recorded Plant at End of Test Year				
1	Deferred Tax Liability - State	Account 282	$ 61,193	$ (99,358)	1
2	Deferred Tax Liability - Federal	Account 282	(1,203,053)	(528,079)	2
3	Excess Deferred Income Taxes	Account 254	0	0	3
4	Alternative Minimum Tax	Account 190	0	0	4
5	Subtotal	Sum Lns 1 - 4	$ (1,141,860)	$ (627,437)	5
	Company-Owned Vehicles - Adjustment No. 6				
6	Deferred Tax Liability - State	Account 282	$ (1,116)	$ (5,535)	6
7	Deferred Tax Liability - Federal	Account 282	(6,053)	(30,030)	7
8	Excess Deferred Income Taxes	Account 254	0	0	8
9	Alternative Minimum Tax	Account 190	0	0	9
10	Subtotal	Sum Lns 6 - 9	$ (7,169)	$ (35,565)	10
	Total Deferred Tax Adjustments				
11	Deferred Tax Liability - State	Ln 1 + Ln 6	$ 60,077	$ (104,893)	11
12	Deferred Tax Liability - Federal	Ln 2 + Ln 7	(1,209,106)	(558,109)	12
13	Excess Deferred Income Taxes	Ln 3 + Ln 8	0	0	13
14	Alternative Minimum Tax	Ln 4 + Ln 9	0	0	14
15	Total	Sum Lns 11 - 14	$ (1,149,029)	$ (663,002)	15
			Sch B-6, Sh 4	Sch B-6, Sh 4	

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF REPRODUCTION COST NEW LESS DEPRECIATION (RCND) OF GAS PLANT BY FUNCTION
AT JANUARY 31, 2019
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description	Reference	RCND 1/31/2019	Adjustments	Adjusted at 1/31/2019	Allocation of System Allocable Plant	Adjusted after Allocation at 1/31/2019	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
				Sch B-2, Sh 1, Col (d)	(c) + (d)	Lns 12-17(e) * Ln 19	(e) + (f)	
	Direct Gross Plant in Service (GPIS)							
1	Intangible Plant	Sch B-4, Sh 41	$ 4,219,850	$ 0	$ 4,219,850	$ 148,564,500	$ 152,784,350	1
2	Storage Plant	Sch B-4, Sh 41	1,772,673	76,200,000	77,972,673	0	77,972,673	2
3	Distribution Plant	Sch B-4, Sh 2-26	5,740,243,053	80,980,126	5,821,223,179	0	5,821,223,179	3
4	General Plant	Sch B-4, Sh 2-26	192,969,133	22,284,281	215,253,414	77,929,290	293,182,704	4
5	Total Direct Gross Plant in Service	Sum Lns 1-4	$ 5,939,204,709	$ 179,464,406	$ 6,118,669,115	$ 226,493,790	$ 6,345,162,906	5
	Direct Accumulated Depreciation							
6	Intangible Plant	Sch B-4, Sh 41	$ 3,009,220	$ 0	$ 3,009,220	$ 107,824,595	$ 110,833,815	6
7	Storage Plant	Sch B-4, Sh 41	0	0	0	0	0	7
8	Distribution Plant	Ln 3 * Sch B-4, Sh 41, Ln 13(b)	2,207,171,103	0	2,207,171,103	0	2,207,171,103	8
9	General Plant	Ln 4 * Sch B-4, Sh 41, Ln 14(b)	64,228,597	(104,738)	64,123,859	19,244,314	83,368,173	9
10	Total Direct Accumulated Depreciation	Sum Lns 6-9	$ 2,274,408,920	$ (104,738)	$ 2,274,304,182	$ 127,068,910	$ 2,401,373,091	10
11	Total Direct Net Plant in Service	Ln 5 - Ln 10	$ 3,664,795,789	$ 179,569,145	$ 3,844,364,934	$ 99,424,881	$ 3,943,789,814	11
					Sch B-1, Sh 1, Col (d)			
	System Allocable GPIS							
12	Intangible Plant	Sch B-4, Sh 41	$ 237,589,747	$ 29,239,725	$ 266,829,472			12
13	General Plant	Sch B-4, Sh 27-40	107,633,979	32,331,028	139,965,007			13
14	Total System Allocable GPIS	Ln 12 + Ln 13	$ 345,223,726	$ 61,570,752	$ 406,794,478			14
	System Allocable Accumulated Depreciation							
15	Intangible Plant	Sch B-4, Sh 41	$ 193,658,510	$ 0	$ 193,658,510			15
16	General Plant	Ln 13 * Sch B-4, Sh 41, Ln 14(c)	35,511,717	(947,940)	34,563,777			16
17	Total Sys. Alloc. Accumulated Depreciation	Ln 15 + Ln 16	$ 229,170,227	$ (947,940)	$ 228,222,287			17
18	Total System Allocable Net Plant in Service	Ln 14 - Ln 17	$ 116,053,499	$ 62,518,692	$ 178,572,192			18
19	AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)	55.68%	55.68%	55.68%			19
20	Sys. Alloc. GPIS Allocated to AZ	Ln 14 * Ln 19	$ 192,212,615	$ 34,281,176	$ 226,493,790			20
21	Sys. Alloc. Accum. Depreciation Allocated to AZ	Ln 17 * Ln 19	127,596,701	(527,791)	127,068,910			21
22	System Allocable Net Plant Allocated to AZ	Ln 20 - Ln 21	$ 64,615,914	$ 34,808,967	$ 99,424,881			22
					Sch B-1, Sh 1, Col (d)			

SOUTHWEST GAS CORPORATION
ARIZONA
HANDY - WHITMAN INDEX OF PUBLIC UTILITY CONSTRUCTION COSTS
PLATEAU DIVISION - GAS UTILITY

		FERC Account Number														
Line No.	Year	360 374 389	375 390	378 385 386 387	397 398	391 395	392 393 394 396	376 Steel	376 Plastic	380 Steel	380 Plastic	381	382	383	384	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
1	1930	1	19	24	15	11	22	19	0	16	0	27	22	37	21	1
2	1931	1	17	24	15	11	20	18	0	15	0	26	22	36	21	2
3	1932	1	16	23	15	11	19	18	0	15	0	25	22	34	21	3
4	1933	1	17	22	15	11	19	17	0	14	0	25	21	34	19	4
5	1934	1	19	22	15	11	20	18	0	15	0	25	21	34	19	5
6	1935	1	18	22	15	11	21	19	0	15	0	25	20	34	20	6
7	1936	1	19	22	15	12	21	18	0	16	0	25	20	34	20	7
8	1937	1	20	24	17	13	23	20	0	17	0	26	22	35	22	8
9	1938	1	20	24	17	13	23	20	0	17	0	26	22	37	23	9
10	1939	1	20	24	17	13	23	20	0	17	0	26	22	40	22	10
11	1940	1	20	26	17	13	24	20	0	18	0	26	22	48	22	11
12	1941	1	22	26	18	13	25	20	0	18	0	26	22	48	23	12
13	1942	1	23	26	19	15	28	21	0	19	0	26	22	48	23	13
14	1943	1	23	26	19	15	29	21	0	19	0	26	22	48	23	14
15	1944	1	24	26	19	15	29	21	0	19	0	26	23	48	23	15
16	1945	1	24	26	19	16	29	22	0	19	0	26	23	48	24	16
17	1946	1	27	29	21	20	34	24	0	22	0	33	25	53	25	17
18	1947	1	32	34	24	23	37	27	0	25	0	41	29	63	28	18
19	1948	1	36	37	26	26	39	31	0	28	0	42	32	64	31	19
20	1949	1	37	39	28	26	40	33	0	30	0	45	34	68	34	20
21	1950	1	39	40	30	27	42	35	0	32	0	48	35	69	34	21
22	1951	1	42	44	31	29	45	37	0	33	0	55	38	74	36	22
23	1952	1	44	45	33	31	46	39	0	35	0	55	39	74	38	23
24	1953	1	44	46	34	33	49	41	0	37	45	55	40	74	40	24
25	1954	1	46	47	36	34	49	44	0	39	46	55	43	74	42	25
26	1955	1	48	49	37	36	51	46	0	41	47	56	44	74	44	26
27	1956	1	52	54	39	39	55	48	0	45	49	63	50	74	49	27
28	1957	1	55	57	41	41	59	52	0	48	52	66	55	76	53	28
29	1958	1	57	60	42	42	62	54	0	50	54	71	57	80	55	29
30	1959	1	58	62	45	45	64	57	0	53	56	71	60	80	58	30
31	1960	1	59	64	46	46	65	58	0	54	57	71	62	80	60	31
32	1961	1	58	64	49	51	67	61	0	58	59	73	63	81	61	32
33	1962	1	59	66	51	53	67	63	71	60	61	79	64	82	62	33
34	1963	1	60	67	52	55	68	64	72	60	62	79	65	82	63	34
35	1964	1	61	68	54	57	70	66	73	63	64	79	65	82	64	35
36	1965	1	64	68	57	60	71	68	74	64	65	79	66	80	64	36
37	1966	1	65	70	58	62	73	69	76	66	68	86	67	80	66	37
38	1967	1	67	72	62	66	76	73	79	69	71	88	69	80	68	38
39	1968	1	71	73	64	70	80	75	81	72	74	88	71	81	70	39
40	1969	1	75	76	69	74	84	80	84	77	78	89	75	83	74	40
41	1970	1	79	83	78	81	88	84	87	84	84	94	83	92	82	41
42	1971	1	87	90	88	87	93	90	92	90	89	100	88	98	88	42
43	1972	1	93	97	95	94	95	96	96	95	95	100	96	100	96	43
44	1973	1	100	100	100	100	100	100	100	100	100	100	100	100	100	44
45	1974	1	118	116	109	109	117	117	112	113	111	111	120	106	120	45
46	1975	1	133	135	122	123	141	133	130	129	127	128	135	125	134	46
47	1976	1	138	148	131	130	153	142	137	138	134	131	145	132	144	47
48	1977	1	148	158	142	141	164	155	147	149	144	136	157	136	156	48
49	1978	1	161	173	151	151	178	171	158	161	155	139	175	144	174	49
50	1979	1	177	187	160	164	197	187	174	176	170	143	191	171	189	50
51	1980	1	194	203	170	178	222	200	193	192	184	149	201	201	199	51
52	1981	1	204	224	185	186	246	219	209	208	197	158	223	210	220	52
53	1982	1	207	246	206	203	263	239	224	226	218	158	246	217	243	53
54	1983	1	215	246	218	209	269	246	232	232	227	146	254	221	252	54
55	1984	1	224	248	220	212	273	251	236	237	230	147	260	230	258	55
56	1985	1	226	243	214	211	276	245	235	234	226	158	249	237	247	56
57	1986	1	231	243	215	218	280	233	238	233	230	166	232	236	232	57
58	1987	1	232	250	216	226	286	241	245	241	236	165	240	243	239	58
59	1988	1	233	267	215	219	295	258	256	246	240	170	263	247	260	59
60	1989	1	232	278	214	213	281	270	273	251	247	177	280	253	277	60
61	1990	1	237	276	220	228	298	276	281	262	256	185	282	269	279	61
62	1991	1	233	279	225	242	320	283	288	272	265	190	287	283	283	62
63	1992	1	238	288	232	249	316	286	290	278	269	192	289	294	286	63
64	1993	1	250	298	236	260	324	294	297	285	277	191	296	297	293	64
65	1994	1	261	310	239	257	331	315	302	293	281	189	325	303	320	65
66	1995	1	265	313	247	246	333	317	305	292	279	190	329	302	324	66
67	1996	1	176	323	254	250	336	319	313	296	287	192	331	303	327	67
68	1997	1	282	332	257	251	351	327	319	301	292	196	341	303	337	68
69	1998	1	285	335	265	254	380	330	324	306	297	196	344	307	340	69
70	1999	1	287	342	275	261	385	341	329	313	304	193	357	306	352	70
71	2000	1	295	352	285	268	389	356	336	323	312	202	376	305	371	71
72	2001	1	303	358	299	280	390	362	344	331	323	209	381	311	377	72
73	2002	1	310	363	309	289	395	367	350	338	333	203	387	319	384	73
74	2003	1	320	365	318	293	401	385	356	347	339	191	410	317	405	74
75	2004	1	342	422	327	298	414	470	368	382	348	183	521	323	507	75
76	2005	1	355	480	337	303	439	568	391	426	364	186	649	340	625	76
77	2006	1	364	494	345	305	457	580	411	436	377	197	664	359	639	77
78	2007	1	382	497	354	317	469	560	431	435	392	226	633	380	612	78
79	2008	1	398	544	365	337	485	602	451	473	411	251	725	397	697	79
80	2009	1	389	544	382	359	501	632	468	485	432	257	717	406	693	80
81	2010	1	399	556	406	375	503	657	460	502	440	254	748	415	723	81
82	2011	1	411	632	416	387	516	741	475	541	454	256	858	429	824	82
83	2012	1	422	663	424	405	538	805	492	575	469	268	936	438	895	83
84	2013	1	431	650	429	412	551	790	494	576	473	295	912	447	874	84
85	2014	1	440	664	437	427	560	787	497	582	481	352	903	459	867	85
86	2015	1	442	659	445	429	567	771	502	578	486	372	880	469	847	86
87	2016	1	447	657	449	440	573	747	510	577	497	388	845	481	817	87
88	2017	1	465	684	473	449	578	788	516	598	507	442	898	487	865	88
89	2018	1	481	712	481	468	576	828	520	618	514	476	948	533	912	89
90	2019	1	488	730	481	468	518	860	518	629	513	477	991	533	951	90

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 360.0 - Land and Land Rights

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	2015	$ 1,702,773	1	1.00	$ 1,702,773	1
2	2016	69,900	1	1.00	69,900	2
3	Total	$ 1,772,673			$ 1,772,673	3

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 374.1 - Land and Land Rights

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	1	1.00	$ 0	1
2	1931	0	1	1.00	0	2
3	1932	0	1	1.00	0	3
4	1933	0	1	1.00	0	4
5	1934	0	1	1.00	0	5
6	1935	0	1	1.00	0	6
7	1936	0	1	1.00	0	7
8	1937	0	1	1.00	0	8
9	1938	0	1	1.00	0	9
10	1939	0	1	1.00	0	10
11	1940	0	1	1.00	0	11
12	1941	0	1	1.00	0	12
13	1942	0	1	1.00	0	13
14	1943	0	1	1.00	0	14
15	1944	0	1	1.00	0	15
16	1945	0	1	1.00	0	16
17	1946	0	1	1.00	0	17
18	1947	0	1	1.00	0	18
19	1948	0	1	1.00	0	19
20	1949	0	1	1.00	0	20
21	1950	0	1	1.00	0	21
22	1951	0	1	1.00	0	22
23	1952	0	1	1.00	0	23
24	1953	0	1	1.00	0	24
25	1954	0	1	1.00	0	25
26	1955	0	1	1.00	0	26
27	1956	0	1	1.00	0	27
28	1957	0	1	1.00	0	28
29	1958	9,746	1	1.00	9,746	29
30	1959	0	1	1.00	0	30
31	1960	0	1	1.00	0	31
32	1961	0	1	1.00	0	32
33	1962	0	1	1.00	0	33
34	1963	0	1	1.00	0	34
35	1964	0	1	1.00	0	35
36	1965	0	1	1.00	0	36
37	1966	0	1	1.00	0	37
38	1967	0	1	1.00	0	38
39	1968	0	1	1.00	0	39
40	1969	0	1	1.00	0	40
41	1970	0	1	1.00	0	41
42	1971	0	1	1.00	0	42
43	1972	0	1	1.00	0	43
44	1973	0	1	1.00	0	44
45	1974	0	1	1.00	0	45
46	1975	254	1	1.00	254	46
47	1976	0	1	1.00	0	47
48	1977	0	1	1.00	0	48
49	1978	0	1	1.00	0	49
50	1979	0	1	1.00	0	50
51	1980	0	1	1.00	0	51
52	1981	0	1	1.00	0	52
53	1982	0	1	1.00	0	53
54	1983	0	1	1.00	0	54
55	1984	0	1	1.00	0	55
56	1985	331,290	1	1.00	331,290	56
57	1986	0	1	1.00	0	57
58	1987	0	1	1.00	0	58
59	1988	0	1	1.00	0	59
60	1989	0	1	1.00	0	60
61	1990	0	1	1.00	0	61
62	1991	0	1	1.00	0	62
63	1992	0	1	1.00	0	63
64	1993	2,500	1	1.00	2,500	64
65	1994	0	1	1.00	0	65
66	1995	0	1	1.00	0	66
67	1996	0	1	1.00	0	67
68	1997	0	1	1.00	0	68
69	1998	0	1	1.00	0	69
70	1999	0	1	1.00	0	70
71	2000	0	1	1.00	0	71
72	2001	0	1	1.00	0	72
73	2002	0	1	1.00	0	73
74	2003	0	1	1.00	0	74
75	2004	0	1	1.00	0	75
76	2005	0	1	1.00	0	76
77	2006	0	1	1.00	0	77
78	2007	0	1	1.00	0	78
79	2008	0	1	1.00	0	79
80	2009	12,113	1	1.00	12,113	80
81	2010	10,139	1	1.00	10,139	81
82	2011	22,262	1	1.00	22,262	82
83	2012	17,362	1	1.00	17,362	83
84	2013	0	1	1.00	0	84
85	2014	0	1	1.00	0	85
86	2015	0	1	1.00	0	86
87	2016	0	1	1.00	0	87
88	2017	0	1	1.00	0	88
89	2018	0	1	1.00	0	89
90	2019	0	1	1.00	0	90
91	Total	$ 405,666			$ 405,666	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 374.2 - Rights of Way

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	1	1.00	$ 0	1
2	1931	0	1	1.00	0	2
3	1932	0	1	1.00	0	3
4	1933	0	1	1.00	0	4
5	1934	0	1	1.00	0	5
6	1935	0	1	1.00	0	6
7	1936	0	1	1.00	0	7
8	1937	0	1	1.00	0	8
9	1938	0	1	1.00	0	9
10	1939	0	1	1.00	0	10
11	1940	111	1	1.00	111	11
12	1941	14	1	1.00	14	12
13	1942	0	1	1.00	0	13
14	1943	160	1	1.00	160	14
15	1944	0	1	1.00	0	15
16	1945	2	1	1.00	2	16
17	1946	0	1	1.00	0	17
18	1947	0	1	1.00	0	18
19	1948	952	1	1.00	952	19
20	1949	139	1	1.00	139	20
21	1950	101	1	1.00	101	21
22	1951	667	1	1.00	667	22
23	1952	183	1	1.00	183	23
24	1953	124	1	1.00	124	24
25	1954	104	1	1.00	104	25
26	1955	121	1	1.00	121	26
27	1956	116	1	1.00	116	27
28	1957	138	1	1.00	138	28
29	1958	146	1	1.00	146	29
30	1959	75	1	1.00	75	30
31	1960	164	1	1.00	164	31
32	1961	178	1	1.00	178	32
33	1962	896	1	1.00	896	33
34	1963	2,944	1	1.00	2,944	34
35	1964	2,322	1	1.00	2,322	35
36	1965	849	1	1.00	849	36
37	1966	1,145	1	1.00	1,145	37
38	1967	664	1	1.00	664	38
39	1968	896	1	1.00	896	39
40	1969	4,059	1	1.00	4,059	40
41	1970	20,184	1	1.00	20,184	41
42	1971	18,376	1	1.00	18,376	42
43	1972	11,259	1	1.00	11,259	43
44	1973	16,606	1	1.00	16,606	44
45	1974	29,634	1	1.00	29,634	45
46	1975	8,365	1	1.00	8,365	46
47	1976	15,469	1	1.00	15,469	47
48	1977	13,306	1	1.00	13,306	48
49	1978	12,233	1	1.00	12,233	49
50	1979	5,998	1	1.00	5,998	50
51	1980	3,835	1	1.00	3,835	51
52	1981	69,501	1	1.00	69,501	52
53	1982	21,828	1	1.00	21,828	53
54	1983	13,467	1	1.00	13,467	54
55	1984	5,304	1	1.00	5,304	55
56	1985	56,285	1	1.00	56,285	56
57	1986	20,552	1	1.00	20,552	57
58	1987	8,770	1	1.00	8,770	58
59	1988	3,206	1	1.00	3,206	59
60	1989	3,127	1	1.00	3,127	60
61	1990	0	1	1.00	0	61
62	1991	0	1	1.00	0	62
63	1992	0	1	1.00	0	63
64	1993	2,250	1	1.00	2,250	64
65	1994	6,025	1	1.00	6,025	65
66	1995	0	1	1.00	0	66
67	1996	0	1	1.00	0	67
68	1997	44,591	1	1.00	44,591	68
69	1998	1,768	1	1.00	1,768	69
70	1999	0	1	1.00	0	70
71	2000	39,620	1	1.00	39,620	71
72	2001	15,864	1	1.00	15,864	72
73	2002	36,423	1	1.00	36,423	73
74	2003	12,148	1	1.00	12,148	74
75	2004	104,102	1	1.00	104,102	75
76	2005	78,132	1	1.00	78,132	76
77	2006	284,871	1	1.00	284,871	77
78	2007	745,071	1	1.00	745,071	78
79	2008	196,021	1	1.00	196,021	79
80	2009	14,416	1	1.00	14,416	80
81	2010	155,388	1	1.00	155,388	81
82	2011	18,196	1	1.00	18,196	82
83	2012	37,200	1	1.00	37,200	83
84	2013	31,066	1	1.00	31,066	84
85	2014	192,215	1	1.00	192,215	85
86	2015	167,804	1	1.00	167,804	86
87	2016	148,089	1	1.00	148,089	87
88	2017	526,016	1	1.00	526,016	88
89	2018	80,584	1	1.00	80,584	89
90	2019	0	1	1.00	0	90
91	Total	$ 3,312,435			$ 3,312,435	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 375 - Structures and Improvements

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	19	25.68	$ 0	1
2	1931	0	17	28.71	0	2
3	1932	0	16	30.50	0	3
4	1933	0	17	28.71	0	4
5	1934	0	19	25.68	0	5
6	1935	0	18	27.11	0	6
7	1936	0	19	25.68	0	7
8	1937	197	20	24.40	4,807	8
9	1938	94	20	24.40	2,294	9
10	1939	1,659	20	24.40	40,480	10
11	1940	373	20	24.40	9,101	11
12	1941	2,797	22	22.18	62,037	12
13	1942	0	23	21.22	0	13
14	1943	0	23	21.22	0	14
15	1944	0	24	20.33	0	15
16	1945	5,437	24	20.33	110,534	16
17	1946	2,032	27	18.07	36,718	17
18	1947	895	32	15.25	13,649	18
19	1948	4,989	36	13.56	67,651	19
20	1949	6,441	37	13.19	84,957	20
21	1950	8,724	39	12.51	109,137	21
22	1951	21,212	42	11.62	246,483	22
23	1952	1,568	44	11.09	17,389	23
24	1953	4,318	44	11.09	47,887	24
25	1954	2,625	46	10.61	27,851	25
26	1955	959	48	10.17	9,753	26
27	1956	4,816	52	9.38	45,174	27
28	1957	0	55	8.87	0	28
29	1958	0	57	8.56	0	29
30	1959	0	58	8.41	0	30
31	1960	0	59	8.27	0	31
32	1961	0	58	8.41	0	32
33	1962	0	59	8.27	0	33
34	1963	0	60	8.13	0	34
35	1964	0	61	8.00	0	35
36	1965	394	64	7.63	3,006	36
37	1966	0	65	7.51	0	37
38	1967	0	67	7.28	0	38
39	1968	0	71	6.87	0	39
40	1969	0	75	6.51	0	40
41	1970	0	79	6.18	0	41
42	1971	0	87	5.61	0	42
43	1972	0	93	5.25	0	43
44	1973	23,733	100	4.88	115,817	44
45	1974	8,122	118	4.14	33,625	45
46	1975	0	133	3.67	0	46
47	1976	0	138	3.54	0	47
48	1977	437	148	3.30	1,442	48
49	1978	674	161	3.03	2,042	49
50	1979	0	177	2.76	0	50
51	1980	0	194	2.52	0	51
52	1981	0	204	2.39	0	52
53	1982	0	207	2.36	0	53
54	1983	0	215	2.27	0	54
55	1984	0	224	2.18	0	55
56	1985	0	226	2.16	0	56
57	1986	0	231	2.11	0	57
58	1987	0	232	2.10	0	58
59	1988	0	233	2.09	0	59
60	1989	0	232	2.10	0	60
61	1990	2,068	237	2.06	4,261	61
62	1991	2,033	233	2.09	4,249	62
63	1992	0	238	2.05	0	63
64	1993	0	250	1.95	0	64
65	1994	0	261	1.87	0	65
66	1995	3,960	265	1.84	7,286	66
67	1996	0	176	2.77	0	67
68	1997	0	282	1.73	0	68
69	1998	0	285	1.71	0	69
70	1999	0	287	1.70	0	70
71	2000	0	295	1.65	0	71
72	2001	0	303	1.61	0	72
73	2002	0	310	1.57	0	73
74	2003	0	320	1.53	0	74
75	2004	0	342	1.43	0	75
76	2005	0	355	1.37	0	76
77	2006	0	364	1.34	0	77
78	2007	0	382	1.28	0	78
79	2008	0	398	1.23	0	79
80	2009	0	389	1.25	0	80
81	2010	0	399	1.22	0	81
82	2011	0	411	1.19	0	82
83	2012	0	422	1.16	0	83
84	2013	0	431	1.13	0	84
85	2014	0	440	1.11	0	85
86	2015	0	442	1.10	0	86
87	2016	0	447	1.09	0	87
88	2017	0	465	1.05	0	88
89	2018	0	481	1.01	0	89
90	2019	0	488	1.00	0	90
91	Total	$ 110,557			$ 1,107,630	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 376 - Mains - Steel

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 62,194	19	45.26	$ 2,814,900	1
2	1931	2,455	18	47.78	117,300	2
3	1932	0	18	47.78	0	3
4	1933	0	17	50.59	0	4
5	1934	2,213	18	47.78	105,737	5
6	1935	7,492	19	45.26	339,088	6
7	1936	0	18	47.78	0	7
8	1937	13,923	20	43.00	598,689	8
9	1938	19,751	20	43.00	849,293	9
10	1939	0	20	43.00	0	10
11	1940	90	20	43.00	3,870	11
12	1941	26,467	20	43.00	1,138,081	12
13	1942	16,128	21	40.95	660,442	13
14	1943	22,408	21	40.95	917,608	14
15	1944	11,830	21	40.95	484,439	15
16	1945	45,235	22	39.09	1,768,236	16
17	1946	829	24	35.83	29,703	17
18	1947	189,599	27	31.85	6,038,728	18
19	1948	594,962	31	27.74	16,504,246	19
20	1949	480,016	33	26.06	12,509,217	20
21	1950	686,118	35	24.57	16,857,919	21
22	1951	636,712	37	23.24	14,797,187	22
23	1952	597,213	39	22.05	13,168,547	23
24	1953	392,751	41	20.98	8,239,916	24
25	1954	559,817	44	19.55	10,944,422	25
26	1955	2,433,446	46	18.70	45,505,440	26
27	1956	992,562	48	17.92	17,786,711	27
28	1957	890,076	52	16.54	14,721,857	28
29	1958	1,603,928	54	15.93	25,550,573	29
30	1959	1,469,694	57	15.09	22,177,682	30
31	1960	1,454,842	58	14.83	21,575,307	31
32	1961	1,480,053	61	14.10	20,868,747	32
33	1962	1,532,354	63	13.65	20,916,632	33
34	1963	1,030,699	64	13.44	13,852,595	34
35	1964	1,418,756	66	13.03	18,486,391	35
36	1965	1,613,934	68	12.65	20,416,265	36
37	1966	1,403,862	69	12.46	17,492,121	37
38	1967	932,664	73	11.78	10,986,782	38
39	1968	600,821	75	11.47	6,891,417	39
40	1969	1,380,594	80	10.75	14,841,386	40
41	1970	798,875	84	10.24	8,180,480	41
42	1971	1,778,066	90	9.56	16,998,311	42
43	1972	3,067,322	96	8.96	27,483,205	43
44	1973	2,425,649	100	8.60	20,860,581	44
45	1974	2,575,239	117	7.35	18,928,007	45
46	1975	1,310,335	133	6.47	8,477,867	46
47	1976	597,295	142	6.06	3,619,608	47
48	1977	1,147,927	155	5.55	6,370,995	48
49	1978	1,118,928	171	5.03	5,628,208	49
50	1979	1,081,955	187	4.60	4,976,993	50
51	1980	1,303,068	200	4.30	5,603,192	51
52	1981	2,886,302	219	3.93	11,343,167	52
53	1982	1,520,695	239	3.60	5,474,502	53
54	1983	2,156,183	246	3.50	7,546,641	54
55	1984	2,220,926	251	3.43	7,617,776	55
56	1985	1,888,744	245	3.51	6,629,491	56
57	1986	2,795,656	233	3.69	10,315,971	57
58	1987	2,642,833	241	3.57	9,434,914	58
59	1988	2,080,371	258	3.33	6,927,635	59
60	1989	1,802,346	270	3.19	5,749,484	60
61	1990	2,858,595	276	3.12	8,918,816	61
62	1991	4,105,213	283	3.04	12,479,848	62
63	1992	4,883,296	286	3.01	14,698,721	63
64	1993	5,015,758	294	2.93	14,696,171	64
65	1994	6,479,391	315	2.73	17,688,737	65
66	1995	8,334,530	317	2.71	22,586,576	66
67	1996	6,612,391	319	2.70	17,853,456	67
68	1997	6,744,673	327	2.63	17,738,490	68
69	1998	6,916,054	330	2.61	18,050,901	69
70	1999	6,318,969	341	2.52	15,923,802	70
71	2000	8,931,590	356	2.42	21,614,448	71
72	2001	12,319,237	362	2.38	29,319,784	72
73	2002	13,738,828	367	2.34	32,148,858	73
74	2003	12,982,890	385	2.23	28,951,845	74
75	2004	21,724,433	470	1.83	39,755,712	75
76	2005	27,773,561	568	1.51	41,938,077	76
77	2006	16,103,905	580	1.48	23,833,779	77
78	2007	29,921,876	560	1.54	46,079,689	78
79	2008	13,668,029	602	1.43	19,545,281	79
80	2009	13,785,370	632	1.36	18,748,103	80
81	2010	18,566,186	657	1.31	24,321,704	81
82	2011	51,627,214	741	1.16	59,887,568	82
83	2012	43,259,467	805	1.07	46,287,630	83
84	2013	22,885,702	790	1.09	24,945,415	84
85	2014	41,485,186	787	1.09	45,218,853	85
86	2015	44,303,334	771	1.12	49,619,734	86
87	2016	20,973,364	747	1.15	24,119,369	87
88	2017	55,170,873	788	1.09	60,136,252	88
89	2018	59,691,211	828	1.04	62,078,859	89
90	2019	4,538,687	860	1.00	4,538,687	90
91	Total	$ 653,525,016			$ 1,462,849,667	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 376 - Mains - Plastic

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	0	0.00	$ 0	1
2	1931	0	0	0.00	0	2
3	1932	0	0	0.00	0	3
4	1933	0	0	0.00	0	4
5	1934	0	0	0.00	0	5
6	1935	0	0	0.00	0	6
7	1936	0	0	0.00	0	7
8	1937	0	0	0.00	0	8
9	1938	0	0	0.00	0	9
10	1939	0	0	0.00	0	10
11	1940	0	0	0.00	0	11
12	1941	188	0	0.00	0	12
13	1942	0	0	0.00	0	13
14	1943	0	0	0.00	0	14
15	1944	0	0	0.00	0	15
16	1945	0	0	0.00	0	16
17	1946	8,678	0	0.00	0	17
18	1947	0	0	0.00	0	18
19	1948	0	0	0.00	0	19
20	1949	0	0	0.00	0	20
21	1950	0	0	0.00	0	21
22	1951	9	0	0.00	0	22
23	1952	0	0	0.00	0	23
24	1953	64	0	0.00	0	24
25	1954	0	0	0.00	0	25
26	1955	265	0	0.00	0	26
27	1956	4,564	0	0.00	0	27
28	1957	7,777	0	0.00	0	28
29	1958	13,487	0	0.00	0	29
30	1959	9,006	0	0.00	0	30
31	1960	21,408	0	0.00	0	31
32	1961	94,029	0	0.00	0	32
33	1962	298,985	71	7.30	2,182,591	33
34	1963	320,693	72	7.19	2,305,783	34
35	1964	373,790	73	7.10	2,653,909	35
36	1965	247,169	74	7.00	1,730,183	36
37	1966	821,616	76	6.82	5,603,421	37
38	1967	939,552	79	6.56	6,163,461	38
39	1968	440,231	81	6.40	2,817,478	39
40	1969	869,736	84	6.17	5,366,271	40
41	1970	529,060	87	5.95	3,147,907	41
42	1971	1,243,304	92	5.63	6,999,802	42
43	1972	1,754,242	96	5.40	9,472,907	43
44	1973	1,057,961	100	5.18	5,480,238	44
45	1974	1,342,594	112	4.63	6,216,210	45
46	1975	824,966	130	3.98	3,283,365	46
47	1976	348,669	137	3.78	1,317,969	47
48	1977	413,735	147	3.52	1,456,347	48
49	1978	211,050	158	3.28	692,244	49
50	1979	580,315	174	2.98	1,729,339	50
51	1980	895,231	193	2.68	2,399,219	51
52	1981	1,442,557	209	2.48	3,577,541	52
53	1982	1,257,288	224	2.31	2,904,335	53
54	1983	3,442,621	232	2.23	7,677,045	54
55	1984	5,584,214	236	2.19	12,229,429	55
56	1985	4,283,151	235	2.20	9,422,932	56
57	1986	15,277,918	238	2.18	33,305,861	57
58	1987	16,448,406	245	2.11	34,706,137	58
59	1988	19,008,384	256	2.02	38,396,936	59
60	1989	14,933,596	273	1.90	28,373,832	60
61	1990	20,283,417	281	1.84	37,321,487	61
62	1991	6,283,942	288	1.80	11,311,096	62
63	1992	9,164,736	290	1.79	16,404,877	63
64	1993	21,926,798	297	1.74	38,152,629	64
65	1994	25,918,082	302	1.72	44,579,101	65
66	1995	32,518,029	305	1.70	55,280,649	66
67	1996	31,204,305	313	1.65	51,487,103	67
68	1997	27,303,438	319	1.62	44,231,570	68
69	1998	31,958,370	324	1.60	51,133,392	69
70	1999	40,244,058	329	1.57	63,183,171	70
71	2000	42,279,544	336	1.54	65,110,498	71
72	2001	44,308,755	344	1.51	66,906,220	72
73	2002	46,977,423	350	1.48	69,526,586	73
74	2003	40,253,504	356	1.46	58,770,116	74
75	2004	47,915,139	368	1.41	67,560,346	75
76	2005	35,432,662	391	1.32	46,771,114	76
77	2006	41,212,054	411	1.26	51,927,188	77
78	2007	38,651,258	431	1.20	46,381,510	78
79	2008	34,245,160	451	1.15	39,381,934	79
80	2009	26,017,382	468	1.11	28,879,294	80
81	2010	42,265,066	460	1.13	47,759,525	81
82	2011	68,062,164	475	1.09	74,187,759	82
83	2012	41,979,517	492	1.05	44,078,493	83
84	2013	65,234,873	494	1.05	68,496,617	84
85	2014	84,234,871	497	1.04	87,604,266	85
86	2015	91,775,488	502	1.03	94,528,753	86
87	2016	86,908,870	510	1.02	88,647,047	87
88	2017	103,086,108	516	1.00	103,086,108	88
89	2018	123,709,062	520	1.00	123,709,062	89
90	2019	1,288,588	518	1.00	1,288,588	90
91	Total	$ 1,447,993,172			$ 1,929,298,791	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 378 - Measuring and Regulating Equipment - Gen.

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	24	30.42	$ 0	1
2	1931	0	24	30.42	0	2
3	1932	0	23	31.74	0	3
4	1933	0	22	33.18	0	4
5	1934	0	22	33.18	0	5
6	1935	0	22	33.18	0	6
7	1936	0	22	33.18	0	7
8	1937	0	24	30.42	0	8
9	1938	0	24	30.42	0	9
10	1939	0	24	30.42	0	10
11	1940	0	26	28.08	0	11
12	1941	0	26	28.08	0	12
13	1942	0	26	28.08	0	13
14	1943	0	26	28.08	0	14
15	1944	0	26	28.08	0	15
16	1945	0	26	28.08	0	16
17	1946	0	29	25.17	0	17
18	1947	0	34	21.47	0	18
19	1948	0	37	19.73	0	19
20	1949	0	39	18.72	0	20
21	1950	0	40	18.25	0	21
22	1951	0	44	16.59	0	22
23	1952	0	45	16.22	0	23
24	1953	0	46	15.87	0	24
25	1954	0	47	15.53	0	25
26	1955	0	49	14.90	0	26
27	1956	936	54	13.52	12,655	27
28	1957	0	57	12.81	0	28
29	1958	2,492	60	12.17	30,328	29
30	1959	9,479	62	11.77	111,568	30
31	1960	702	64	11.41	8,010	31
32	1961	1,566	64	11.41	17,868	32
33	1962	594	66	11.06	6,570	33
34	1963	329	67	10.90	3,586	34
35	1964	3,436	68	10.74	36,903	35
36	1965	8,224	68	10.74	88,326	36
37	1966	16,845	70	10.43	175,693	37
38	1967	1,213	72	10.14	12,300	38
39	1968	5,822	73	10.00	58,220	39
40	1969	9,130	76	9.61	87,739	40
41	1970	6,393	83	8.80	56,258	41
42	1971	20,140	90	8.11	163,335	42
43	1972	99,462	97	7.53	748,949	43
44	1973	2,273	100	7.30	16,593	44
45	1974	21,401	116	6.29	134,612	45
46	1975	8,724	135	5.41	47,197	46
47	1976	0	148	4.93	0	47
48	1977	6,752	158	4.62	31,194	48
49	1978	46,157	173	4.22	194,783	49
50	1979	19,178	187	3.90	74,794	50
51	1980	38,905	203	3.60	140,058	51
52	1981	7,960	224	3.26	25,950	52
53	1982	57,805	246	2.97	171,681	53
54	1983	48,323	246	2.97	143,519	54
55	1984	134,635	248	2.94	395,827	55
56	1985	7,674	243	3.00	23,022	56
57	1986	131,658	243	3.00	394,974	57
58	1987	61,078	250	2.92	178,348	58
59	1988	158,270	267	2.73	432,077	59
60	1989	43,252	278	2.63	113,753	60
61	1990	122,292	276	2.64	322,851	61
62	1991	76,255	279	2.62	199,788	62
63	1992	216,737	288	2.53	548,345	63
64	1993	317,973	298	2.45	779,034	64
65	1994	671,896	310	2.35	1,578,956	65
66	1995	817,501	313	2.33	1,904,777	66
67	1996	999,174	323	2.26	2,258,133	67
68	1997	461,159	332	2.20	1,014,550	68
69	1998	1,737,827	335	2.18	3,788,463	69
70	1999	3,746,193	342	2.13	7,979,391	70
71	2000	848,705	352	2.07	1,756,819	71
72	2001	1,386,585	358	2.04	2,828,633	72
73	2002	2,764,005	363	2.01	5,555,650	73
74	2003	1,319,831	365	2.00	2,639,662	74
75	2004	2,352,864	422	1.73	4,070,455	75
76	2005	1,799,539	480	1.52	2,735,299	76
77	2006	3,449,015	494	1.48	5,104,542	77
78	2007	5,516,544	497	1.47	8,109,320	78
79	2008	2,799,605	544	1.34	3,751,471	79
80	2009	4,158,447	544	1.34	5,572,319	80
81	2010	9,490,984	556	1.31	12,433,189	81
82	2011	5,066,962	632	1.16	5,877,676	82
83	2012	4,072,242	663	1.10	4,479,466	83
84	2013	2,980,758	650	1.12	3,338,449	84
85	2014	3,254,190	664	1.10	3,579,609	85
86	2015	11,845,568	659	1.11	13,148,580	86
87	2016	2,334,155	657	1.11	2,590,912	87
88	2017	3,195,004	684	1.07	3,418,654	88
89	2018	4,480,294	712	1.03	4,614,703	89
90	2019	222,782	730	1.00	222,782	90
91	Total	$ 83,485,894			$ 120,339,168	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 380 - Services - Steel

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 7,161	16	39.31	$ 281,499	1
2	1931	0	15	41.93	0	2
3	1932	85	15	41.93	3,564	3
4	1933	0	14	44.93	0	4
5	1934	9	15	41.93	377	5
6	1935	0	15	41.93	0	6
7	1936	0	16	39.31	0	7
8	1937	0	17	37.00	0	8
9	1938	32	17	37.00	1,184	9
10	1939	693	17	37.00	25,641	10
11	1940	42	18	34.94	1,467	11
12	1941	4,176	18	34.94	145,909	12
13	1942	10,408	19	33.11	344,609	13
14	1943	721	19	33.11	23,872	14
15	1944	14,927	19	33.11	494,233	15
16	1945	30,374	19	33.11	1,005,683	16
17	1946	64,254	22	28.59	1,837,022	17
18	1947	121,613	25	25.16	3,059,783	18
19	1948	212,279	28	22.46	4,767,786	19
20	1949	41,949	30	20.97	879,671	20
21	1950	271,327	32	19.66	5,334,289	21
22	1951	383,096	33	19.06	7,301,810	22
23	1952	448,592	35	17.97	8,061,198	23
24	1953	329,248	37	17.00	5,597,216	24
25	1954	313,787	39	16.13	5,061,384	25
26	1955	920,349	41	15.34	14,118,154	26
27	1956	540,956	45	13.98	7,562,565	27
28	1957	564,890	48	13.10	7,400,059	28
29	1958	554,520	50	12.58	6,975,862	29
30	1959	203,519	53	11.87	2,415,771	30
31	1960	8,619	54	11.65	100,411	31
32	1961	26,221	58	10.84	284,236	32
33	1962	23,813	60	10.48	249,560	33
34	1963	16,610	60	10.48	174,073	34
35	1964	7,200	63	9.98	71,856	35
36	1965	34,640	64	9.83	340,511	36
37	1966	10,821	66	9.53	103,124	37
38	1967	4,574	69	9.12	41,715	38
39	1968	5,279	72	8.74	46,138	39
40	1969	1,488	77	8.17	12,157	40
41	1970	9,955	84	7.49	74,563	41
42	1971	5,325	90	6.99	37,222	42
43	1972	31,166	95	6.62	206,319	43
44	1973	23,091	100	6.29	145,242	44
45	1974	51,122	113	5.57	284,750	45
46	1975	5,293	129	4.88	25,830	46
47	1976	6,301	138	4.56	28,733	47
48	1977	9,562	149	4.22	40,352	48
49	1978	2,958	161	3.91	11,566	49
50	1979	94,261	176	3.57	336,512	50
51	1980	197,790	192	3.28	648,751	51
52	1981	216,195	208	3.02	652,909	52
53	1982	17,011	226	2.78	47,291	53
54	1983	361,216	232	2.71	978,895	54
55	1984	186,660	237	2.65	494,649	55
56	1985	18,541	234	2.69	49,875	56
57	1986	22,675	233	2.70	61,223	57
58	1987	9,211	241	2.61	24,041	58
59	1988	11,914	246	2.56	30,500	59
60	1989	6,115	251	2.51	15,349	60
61	1990	86,210	262	2.40	206,904	61
62	1991	90,575	272	2.31	209,228	62
63	1992	75,603	278	2.26	170,863	63
64	1993	1,110,810	285	2.21	2,454,890	64
65	1994	394,024	293	2.15	847,152	65
66	1995	655,819	292	2.15	1,410,011	66
67	1996	206,105	296	2.13	439,004	67
68	1997	278,379	301	2.09	581,812	68
69	1998	429,014	306	2.06	883,769	69
70	1999	221,704	313	2.01	445,625	70
71	2000	181,989	323	1.95	354,879	71
72	2001	218,664	331	1.90	415,462	72
73	2002	291,827	338	1.86	542,798	73
74	2003	244,016	347	1.81	441,669	74
75	2004	387,270	382	1.65	638,996	75
76	2005	180,807	426	1.48	267,594	76
77	2006	78,661	436	1.44	113,272	77
78	2007	310,256	435	1.45	449,871	78
79	2008	208,587	473	1.33	277,421	79
80	2009	292,704	485	1.30	380,515	80
81	2010	121,719	502	1.25	152,149	81
82	2011	151,210	541	1.16	175,404	82
83	2012	141,811	575	1.09	154,574	83
84	2013	222,625	576	1.09	242,661	84
85	2014	347,594	582	1.08	375,402	85
86	2015	118,554	578	1.09	129,224	86
87	2016	422,650	577	1.09	460,689	87
88	2017	392,206	598	1.05	411,816	88
89	2018	1,801,637	618	1.02	1,837,670	89
90	2019	259,508	629	1.00	259,508	90
91	Total	$ 16,387,172			$ 104,049,793	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 380 - Services - Plastic

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 1	0	0.00	$ 0	1
2	1931	0	0	0.00	0	2
3	1932	0	0	0.00	0	3
4	1933	0	0	0.00	0	4
5	1934	0	0	0.00	0	5
6	1935	92	0	0.00	0	6
7	1936	2	0	0.00	0	7
8	1937	77	0	0.00	0	8
9	1938	57	0	0.00	0	9
10	1939	3	0	0.00	0	10
11	1940	343	0	0.00	0	11
12	1941	0	0	0.00	0	12
13	1942	11	0	0.00	0	13
14	1943	0	0	0.00	0	14
15	1944	1	0	0.00	0	15
16	1945	0	0	0.00	0	16
17	1946	0	0	0.00	0	17
18	1947	5	0	0.00	0	18
19	1948	127	0	0.00	0	19
20	1949	13,308	0	0.00	0	20
21	1950	0	0	0.00	0	21
22	1951	329	0	0.00	0	22
23	1952	0	0	0.00	0	23
24	1953	7,774	45	11.40	88,624	24
25	1954	18,386	46	11.15	205,004	25
26	1955	90,860	47	10.91	991,283	26
27	1956	63,142	49	10.47	661,097	27
28	1957	135,991	52	9.87	1,342,231	28
29	1958	171,774	54	9.50	1,631,853	29
30	1959	421,291	56	9.16	3,859,026	30
31	1960	161,836	57	9.00	1,456,524	31
32	1961	197,004	59	8.69	1,711,965	32
33	1962	365,939	61	8.41	3,077,547	33
34	1963	380,675	62	8.27	3,148,182	34
35	1964	327,404	64	8.02	2,625,780	35
36	1965	354,878	65	7.89	2,799,987	36
37	1966	286,972	68	7.54	2,163,769	37
38	1967	322,484	71	7.23	2,331,559	38
39	1968	204,032	74	6.93	1,413,942	39
40	1969	3,375	78	6.58	22,208	40
41	1970	56,566	84	6.11	345,618	41
42	1971	105,690	89	5.76	608,774	42
43	1972	237,405	95	5.40	1,281,987	43
44	1973	116,016	100	5.13	595,162	44
45	1974	640,941	111	4.62	2,961,147	45
46	1975	145,488	127	4.04	587,772	46
47	1976	147,598	134	3.83	565,300	47
48	1977	94,451	144	3.56	336,246	48
49	1978	31,320	155	3.31	103,669	49
50	1979	872,898	170	3.02	2,636,152	50
51	1980	1,214,675	184	2.79	3,388,943	51
52	1981	1,506,041	197	2.60	3,915,707	52
53	1982	931,999	218	2.35	2,190,198	53
54	1983	13,852,040	227	2.26	31,305,610	54
55	1984	14,715,552	230	2.23	32,815,681	55
56	1985	7,533,854	226	2.27	17,101,849	56
57	1986	15,581,898	230	2.23	34,747,633	57
58	1987	14,829,987	236	2.17	32,181,072	58
59	1988	13,795,708	240	2.14	29,522,815	59
60	1989	10,748,288	247	2.08	22,356,439	60
61	1990	14,394,296	256	2.00	28,788,592	61
62	1991	6,205,006	265	1.94	12,037,712	62
63	1992	10,737,711	269	1.91	20,509,028	63
64	1993	13,499,268	277	1.85	24,973,646	64
65	1994	20,572,320	281	1.83	37,647,346	65
66	1995	22,924,459	279	1.84	42,181,005	66
67	1996	27,407,170	287	1.79	49,058,834	67
68	1997	24,400,944	292	1.76	42,945,661	68
69	1998	25,159,881	297	1.73	43,526,594	69
70	1999	31,813,231	304	1.69	53,764,360	70
71	2000	28,951,622	312	1.64	47,480,660	71
72	2001	29,878,771	323	1.59	47,507,246	72
73	2002	30,685,944	333	1.54	47,256,354	73
74	2003	29,931,832	339	1.51	45,197,066	74
75	2004	29,932,608	348	1.47	44,000,934	75
76	2005	27,828,750	364	1.41	39,238,538	76
77	2006	36,497,584	377	1.36	49,636,714	77
78	2007	29,413,695	392	1.31	38,531,940	78
79	2008	28,447,159	411	1.25	35,558,949	79
80	2009	21,292,121	432	1.19	25,337,624	80
81	2010	26,150,788	440	1.17	30,596,422	81
82	2011	20,570,174	454	1.13	23,244,297	82
83	2012	25,294,882	469	1.09	27,571,421	83
84	2013	27,042,824	473	1.08	29,206,250	84
85	2014	31,474,387	481	1.07	33,677,594	85
86	2015	42,691,485	486	1.06	45,252,974	86
87	2016	51,969,043	497	1.03	53,528,114	87
88	2017	75,797,515	507	1.01	76,555,490	88
89	2018	108,916,411	514	1.00	108,916,411	89
90	2019	6,167,781	513	1.00	6,167,781	90
91	Total	$ 1,006,736,250			$ 1,458,973,912	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 381 - Meters, Regulators, and Installations

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 36,706	27	17.67	$ 648,595	1
2	1931	61	26	18.35	1,119	2
3	1932	82	25	19.08	1,565	3
4	1933	61	25	19.08	1,164	4
5	1934	82	25	19.08	1,565	5
6	1935	80	25	19.08	1,526	6
7	1936	69,796	25	19.08	1,331,708	7
8	1937	10,559	26	18.35	193,758	8
9	1938	4,973	26	18.35	91,255	9
10	1939	2,149	26	18.35	39,434	10
11	1940	3,739	26	18.35	68,611	11
12	1941	9,893	26	18.35	181,537	12
13	1942	10,625	26	18.35	194,969	13
14	1943	10,723	26	18.35	196,767	14
15	1944	5,266	26	18.35	96,631	15
16	1945	5,902	26	18.35	108,302	16
17	1946	17,413	33	14.45	251,618	17
18	1947	33,623	41	11.63	391,035	18
19	1948	70,338	42	11.36	799,040	19
20	1949	57,171	45	10.60	606,013	20
21	1950	43,012	48	9.94	427,539	21
22	1951	78,207	55	8.67	678,055	22
23	1952	45,137	55	8.67	391,338	23
24	1953	64,168	55	8.67	556,337	24
25	1954	31,716	55	8.67	274,978	25
26	1955	32,364	56	8.52	275,741	26
27	1956	56,766	63	7.57	429,719	27
28	1957	53,270	66	7.23	385,142	28
29	1958	79,613	71	6.72	534,999	29
30	1959	87,805	71	6.72	590,050	30
31	1960	91,164	71	6.72	612,622	31
32	1961	86,700	73	6.53	566,151	32
33	1962	80,950	79	6.04	488,938	33
34	1963	99,879	79	6.04	603,269	34
35	1964	70,893	79	6.04	428,194	35
36	1965	60,589	79	6.04	365,958	36
37	1966	30,912	86	5.55	171,562	37
38	1967	78,323	88	5.42	424,511	38
39	1968	95,065	88	5.42	515,252	39
40	1969	81,817	89	5.36	438,539	40
41	1970	138,013	94	5.07	699,726	41
42	1971	244,201	100	4.77	1,164,839	42
43	1972	324,956	100	4.77	1,550,040	43
44	1973	375,076	100	4.77	1,789,113	44
45	1974	404,354	111	4.30	1,738,722	45
46	1975	269,326	128	3.73	1,004,586	46
47	1976	208,911	131	3.64	760,436	47
48	1977	276,528	136	3.51	970,613	48
49	1978	195,379	139	3.43	670,150	49
50	1979	462,025	143	3.34	1,543,164	50
51	1980	837,128	149	3.20	2,678,810	51
52	1981	571,916	158	3.02	1,727,186	52
53	1982	713,980	158	3.02	2,156,220	53
54	1983	1,784,556	146	3.27	5,835,498	54
55	1984	1,140,637	147	3.24	3,695,664	55
56	1985	2,048,947	158	3.02	6,187,820	56
57	1986	995,051	166	2.87	2,855,796	57
58	1987	1,180,752	165	2.89	3,412,373	58
59	1988	2,460,145	170	2.81	6,913,007	59
60	1989	2,671,265	177	2.69	7,185,703	60
61	1990	1,934,602	185	2.58	4,991,273	61
62	1991	3,154,529	190	2.51	7,917,868	62
63	1992	1,822,511	192	2.48	4,519,827	63
64	1993	206,131	191	2.50	515,328	64
65	1994	5,418,864	189	2.52	13,655,537	65
66	1995	4,371,713	190	2.51	10,973,000	66
67	1996	4,252,550	192	2.48	10,546,324	67
68	1997	4,154,762	196	2.43	10,096,072	68
69	1998	4,584,050	196	2.43	11,139,242	69
70	1999	9,102,404	193	2.47	22,482,938	70
71	2000	6,603,038	202	2.36	15,583,170	71
72	2001	7,593,287	209	2.28	17,312,694	72
73	2002	9,012,632	203	2.35	21,179,685	73
74	2003	10,202,432	191	2.50	25,506,080	74
75	2004	13,335,792	183	2.61	34,806,417	75
76	2005	12,556,865	186	2.56	32,145,574	76
77	2006	33,012,917	197	2.42	79,891,259	77
78	2007	25,761,869	226	2.11	54,357,544	78
79	2008	12,566,995	251	1.90	23,877,291	79
80	2009	5,110,523	257	1.86	9,505,573	80
81	2010	3,546,567	254	1.88	6,667,546	81
82	2011	3,670,084	256	1.86	6,826,356	82
83	2012	14,756,609	268	1.78	26,266,764	83
84	2013	13,646,106	295	1.62	22,106,692	84
85	2014	10,476,727	352	1.36	14,248,349	85
86	2015	26,236,693	372	1.28	33,582,967	86
87	2016	9,668,876	388	1.23	11,892,717	87
88	2017	11,711,783	442	1.08	12,648,726	88
89	2018	17,821,670	476	1.00	17,821,670	89
90	2019	2,257,108	477	1.00	2,257,108	90
91	Total	$ 307,551,427			$ 634,226,163	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 385 - Measuring and Regulating Equipment - Ind.

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	24	30.42	$ 0	1
2	1931	0	24	30.42	0	2
3	1932	0	23	31.74	0	3
4	1933	0	22	33.18	0	4
5	1934	0	22	33.18	0	5
6	1935	0	22	33.18	0	6
7	1936	0	22	33.18	0	7
8	1937	0	24	30.42	0	8
9	1938	0	24	30.42	0	9
10	1939	0	24	30.42	0	10
11	1940	0	26	28.08	0	11
12	1941	0	26	28.08	0	12
13	1942	0	26	28.08	0	13
14	1943	0	26	28.08	0	14
15	1944	0	26	28.08	0	15
16	1945	0	26	28.08	0	16
17	1946	0	29	25.17	0	17
18	1947	0	34	21.47	0	18
19	1948	0	37	19.73	0	19
20	1949	0	39	18.72	0	20
21	1950	0	40	18.25	0	21
22	1951	0	44	16.59	0	22
23	1952	0	45	16.22	0	23
24	1953	0	46	15.87	0	24
25	1954	0	47	15.53	0	25
26	1955	0	49	14.90	0	26
27	1956	0	54	13.52	0	27
28	1957	0	57	12.81	0	28
29	1958	0	60	12.17	0	29
30	1959	0	62	11.77	0	30
31	1960	0	64	11.41	0	31
32	1961	0	64	11.41	0	32
33	1962	0	66	11.06	0	33
34	1963	0	67	10.90	0	34
35	1964	0	68	10.74	0	35
36	1965	0	68	10.74	0	36
37	1966	0	70	10.43	0	37
38	1967	0	72	10.14	0	38
39	1968	53,003	73	10.00	530,030	39
40	1969	0	76	9.61	0	40
41	1970	0	83	8.80	0	41
42	1971	0	90	8.11	0	42
43	1972	21,891	97	7.53	164,839	43
44	1973	32,288	100	7.30	235,702	44
45	1974	103,218	116	6.29	649,241	45
46	1975	76,790	135	5.41	415,434	46
47	1976	45,302	148	4.93	223,339	47
48	1977	16,356	158	4.62	75,565	48
49	1978	17,162	173	4.22	72,424	49
50	1979	31,941	187	3.90	124,570	50
51	1980	123,098	203	3.60	443,153	51
52	1981	102,045	224	3.26	332,667	52
53	1982	140,659	246	2.97	417,757	53
54	1983	172,078	246	2.97	511,072	54
55	1984	350,379	248	2.94	1,030,114	55
56	1985	61,717	243	3.00	185,151	56
57	1986	156,319	243	3.00	468,957	57
58	1987	14,460	250	2.92	42,223	58
59	1988	164,131	267	2.73	448,078	59
60	1989	89,818	278	2.63	236,221	60
61	1990	52,403	276	2.64	138,344	61
62	1991	61,230	279	2.62	160,423	62
63	1992	35,239	288	2.53	89,155	63
64	1993	190,450	298	2.45	466,603	64
65	1994	231,812	310	2.35	544,758	65
66	1995	326,694	313	2.33	761,197	66
67	1996	461,199	323	2.26	1,042,310	67
68	1997	546,746	332	2.20	1,202,841	68
69	1998	675,648	335	2.18	1,472,913	69
70	1999	521,190	342	2.13	1,110,135	70
71	2000	191,839	352	2.07	397,107	71
72	2001	289,260	358	2.04	590,090	72
73	2002	347,407	363	2.01	698,288	73
74	2003	231,876	365	2.00	463,752	74
75	2004	344,321	422	1.73	595,675	75
76	2005	402,876	480	1.52	612,372	76
77	2006	335,049	494	1.48	495,873	77
78	2007	460,539	497	1.47	676,992	78
79	2008	618,826	544	1.34	829,227	79
80	2009	2,161,353	544	1.34	2,896,213	80
81	2010	300,863	556	1.31	394,131	81
82	2011	246,214	632	1.16	285,608	82
83	2012	165,580	663	1.10	182,138	83
84	2013	302,603	650	1.12	338,915	84
85	2014	338,672	664	1.10	372,539	85
86	2015	164,175	659	1.11	182,234	86
87	2016	159,896	657	1.11	177,485	87
88	2017	102,997	684	1.07	110,207	88
89	2018	356,489	712	1.03	367,184	89
90	2019	49,041	730	1.00	49,041	90
91	Total	$ 12,445,142			$ 24,310,287	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 387 - Other Distribution Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	24	30.42	$ 0	1
2	1931	0	24	30.42	0	2
3	1932	0	23	31.74	0	3
4	1933	0	22	33.18	0	4
5	1934	0	22	33.18	0	5
6	1935	0	22	33.18	0	6
7	1936	0	22	33.18	0	7
8	1937	0	24	30.42	0	8
9	1938	0	24	30.42	0	9
10	1939	0	24	30.42	0	10
11	1940	0	26	28.08	0	11
12	1941	0	26	28.08	0	12
13	1942	0	26	28.08	0	13
14	1943	0	26	28.08	0	14
15	1944	0	26	28.08	0	15
16	1945	0	26	28.08	0	16
17	1946	0	29	25.17	0	17
18	1947	0	34	21.47	0	18
19	1948	0	37	19.73	0	19
20	1949	0	39	18.72	0	20
21	1950	0	40	18.25	0	21
22	1951	0	44	16.59	0	22
23	1952	0	45	16.22	0	23
24	1953	0	46	15.87	0	24
25	1954	0	47	15.53	0	25
26	1955	0	49	14.90	0	26
27	1956	0	54	13.52	0	27
28	1957	0	57	12.81	0	28
29	1958	0	60	12.17	0	29
30	1959	0	62	11.77	0	30
31	1960	0	64	11.41	0	31
32	1961	0	64	11.41	0	32
33	1962	0	66	11.06	0	33
34	1963	0	67	10.90	0	34
35	1964	0	68	10.74	0	35
36	1965	0	68	10.74	0	36
37	1966	0	70	10.43	0	37
38	1967	0	72	10.14	0	38
39	1968	0	73	10.00	0	39
40	1969	0	76	9.61	0	40
41	1970	0	83	8.80	0	41
42	1971	0	90	8.11	0	42
43	1972	0	97	7.53	0	43
44	1973	0	100	7.30	0	44
45	1974	0	116	6.29	0	45
46	1975	2,619	135	5.41	14,169	46
47	1976	0	148	4.93	0	47
48	1977	0	158	4.62	0	48
49	1978	0	173	4.22	0	49
50	1979	35,268	187	3.90	137,545	50
51	1980	34,199	203	3.60	123,116	51
52	1981	88,691	224	3.26	289,133	52
53	1982	254,179	246	2.97	754,912	53
54	1983	0	246	2.97	0	54
55	1984	12,674	248	2.94	37,262	55
56	1985	0	243	3.00	0	56
57	1986	4,468	243	3.00	13,404	57
58	1987	0	250	2.92	0	58
59	1988	0	267	2.73	0	59
60	1989	0	278	2.63	0	60
61	1990	0	276	2.64	0	61
62	1991	0	279	2.62	0	62
63	1992	0	288	2.53	0	63
64	1993	0	298	2.45	0	64
65	1994	0	310	2.35	0	65
66	1995	0	313	2.33	0	66
67	1996	0	323	2.26	0	67
68	1997	0	332	2.20	0	68
69	1998	0	335	2.18	0	69
70	1999	0	342	2.13	0	70
71	2000	0	352	2.07	0	71
72	2001	0	358	2.04	0	72
73	2002	0	363	2.01	0	73
74	2003	0	365	2.00	0	74
75	2004	0	422	1.73	0	75
76	2005	0	480	1.52	0	76
77	2006	0	494	1.48	0	77
78	2007	0	497	1.47	0	78
79	2008	0	544	1.34	0	79
80	2009	0	544	1.34	0	80
81	2010	0	556	1.31	0	81
82	2011	0	632	1.16	0	82
83	2012	0	663	1.10	0	83
84	2013	0	650	1.12	0	84
85	2014	0	664	1.10	0	85
86	2015	0	659	1.11	0	86
87	2016	0	657	1.11	0	87
88	2017	0	684	1.07	0	88
89	2018	0	712	1.03	0	89
90	2019	0	730	1.00	0	90
91	Total	$ 432,098			$ 1,369,541	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 389 - Land and Land Rights

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	1	1.00	$ 0	1
2	1931	0	1	1.00	0	2
3	1932	0	1	1.00	0	3
4	1933	0	1	1.00	0	4
5	1934	0	1	1.00	0	5
6	1935	0	1	1.00	0	6
7	1936	0	1	1.00	0	7
8	1937	0	1	1.00	0	8
9	1938	0	1	1.00	0	9
10	1939	0	1	1.00	0	10
11	1940	0	1	1.00	0	11
12	1941	0	1	1.00	0	12
13	1942	0	1	1.00	0	13
14	1943	0	1	1.00	0	14
15	1944	0	1	1.00	0	15
16	1945	0	1	1.00	0	16
17	1946	0	1	1.00	0	17
18	1947	0	1	1.00	0	18
19	1948	0	1	1.00	0	19
20	1949	0	1	1.00	0	20
21	1950	0	1	1.00	0	21
22	1951	0	1	1.00	0	22
23	1952	0	1	1.00	0	23
24	1953	0	1	1.00	0	24
25	1954	0	1	1.00	0	25
26	1955	0	1	1.00	0	26
27	1956	0	1	1.00	0	27
28	1957	0	1	1.00	0	28
29	1958	0	1	1.00	0	29
30	1959	0	1	1.00	0	30
31	1960	0	1	1.00	0	31
32	1961	0	1	1.00	0	32
33	1962	0	1	1.00	0	33
34	1963	0	1	1.00	0	34
35	1964	0	1	1.00	0	35
36	1965	0	1	1.00	0	36
37	1966	0	1	1.00	0	37
38	1967	0	1	1.00	0	38
39	1968	0	1	1.00	0	39
40	1969	0	1	1.00	0	40
41	1970	2,027	1	1.00	2,027	41
42	1971	0	1	1.00	0	42
43	1972	0	1	1.00	0	43
44	1973	0	1	1.00	0	44
45	1974	0	1	1.00	0	45
46	1975	0	1	1.00	0	46
47	1976	0	1	1.00	0	47
48	1977	0	1	1.00	0	48
49	1978	0	1	1.00	0	49
50	1979	0	1	1.00	0	50
51	1980	573,337	1	1.00	573,337	51
52	1981	0	1	1.00	0	52
53	1982	0	1	1.00	0	53
54	1983	0	1	1.00	0	54
55	1984	792,870	1	1.00	792,870	55
56	1985	895,545	1	1.00	895,545	56
57	1986	288,000	1	1.00	288,000	57
58	1987	0	1	1.00	0	58
59	1988	0	1	1.00	0	59
60	1989	3,091,145	1	1.00	3,091,145	60
61	1990	0	1	1.00	0	61
62	1991	0	1	1.00	0	62
63	1992	0	1	1.00	0	63
64	1993	0	1	1.00	0	64
65	1994	0	1	1.00	0	65
66	1995	0	1	1.00	0	66
67	1996	0	1	1.00	0	67
68	1997	173,927	1	1.00	173,927	68
69	1998	0	1	1.00	0	69
70	1999	0	1	1.00	0	70
71	2000	0	1	1.00	0	71
72	2001	0	1	1.00	0	72
73	2002	0	1	1.00	0	73
74	2003	0	1	1.00	0	74
75	2004	0	1	1.00	0	75
76	2005	0	1	1.00	0	76
77	2006	0	1	1.00	0	77
78	2007	1,963,827	1	1.00	1,963,827	78
79	2008	6,724,780	1	1.00	6,724,780	79
80	2009	49,980	1	1.00	49,980	80
81	2010	19,406	1	1.00	19,406	81
82	2011	0	1	1.00	0	82
83	2012	0	1	1.00	0	83
84	2013	0	1	1.00	0	84
85	2014	1,507,492	1	1.00	1,507,492	85
86	2015	0	1	1.00	0	86
87	2016	509,933	1	1.00	509,933	87
88	2017	421,201	1	1.00	421,201	88
89	2018	199,187	1	1.00	199,187	89
90	2019	0	1	1.00	0	90
91	Total	$ 17,212,657			$ 17,212,657	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 390.1 - Structures and Improvements

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	19	25.68	$ 0	1
2	1931	0	17	28.71	0	2
3	1932	0	16	30.50	0	3
4	1933	0	17	28.71	0	4
5	1934	0	19	25.68	0	5
6	1935	0	18	27.11	0	6
7	1936	0	19	25.68	0	7
8	1937	0	20	24.40	0	8
9	1938	0	20	24.40	0	9
10	1939	0	20	24.40	0	10
11	1940	0	20	24.40	0	11
12	1941	0	22	22.18	0	12
13	1942	0	23	21.22	0	13
14	1943	0	23	21.22	0	14
15	1944	0	24	20.33	0	15
16	1945	0	24	20.33	0	16
17	1946	0	27	18.07	0	17
18	1947	0	32	15.25	0	18
19	1948	0	36	13.56	0	19
20	1949	0	37	13.19	0	20
21	1950	0	39	12.51	0	21
22	1951	0	42	11.62	0	22
23	1952	0	44	11.09	0	23
24	1953	0	44	11.09	0	24
25	1954	0	46	10.61	0	25
26	1955	0	48	10.17	0	26
27	1956	0	52	9.38	0	27
28	1957	0	55	8.87	0	28
29	1958	0	57	8.56	0	29
30	1959	0	58	8.41	0	30
31	1960	0	59	8.27	0	31
32	1961	0	58	8.41	0	32
33	1962	0	59	8.27	0	33
34	1963	0	60	8.13	0	34
35	1964	0	61	8.00	0	35
36	1965	0	64	7.63	0	36
37	1966	0	65	7.51	0	37
38	1967	0	67	7.28	0	38
39	1968	0	71	6.87	0	39
40	1969	0	75	6.51	0	40
41	1970	0	79	6.18	0	41
42	1971	0	87	5.61	0	42
43	1972	0	93	5.25	0	43
44	1973	0	100	4.88	0	44
45	1974	0	118	4.14	0	45
46	1975	0	133	3.67	0	46
47	1976	0	138	3.54	0	47
48	1977	310,920	148	3.30	1,026,036	48
49	1978	2,837	161	3.03	8,596	49
50	1979	0	177	2.76	0	50
51	1980	3,210,683	194	2.52	8,090,921	51
52	1981	28,662	204	2.39	68,502	52
53	1982	0	207	2.36	0	53
54	1983	0	215	2.27	0	54
55	1984	2,259,388	224	2.18	4,925,466	55
56	1985	1,355,801	226	2.16	2,928,530	56
57	1986	979,247	231	2.11	2,066,211	57
58	1987	7,122	232	2.10	14,956	58
59	1988	4,672,049	233	2.09	9,764,582	59
60	1989	2,615,976	232	2.10	5,493,550	60
61	1990	152,713	237	2.06	314,589	61
62	1991	831,926	233	2.09	1,738,725	62
63	1992	17,942	238	2.05	36,781	63
64	1993	20,803	250	1.95	40,566	64
65	1994	0	261	1.87	0	65
66	1995	282,554	265	1.84	519,899	66
67	1996	39,764	176	2.77	110,146	67
68	1997	5,477	282	1.73	9,475	68
69	1998	178,764	285	1.71	305,686	69
70	1999	751,319	287	1.70	1,277,242	70
71	2000	228,993	295	1.65	377,838	71
72	2001	133,330	303	1.61	214,661	72
73	2002	171,939	310	1.57	269,944	73
74	2003	182,899	320	1.53	279,835	74
75	2004	303,320	342	1.43	433,748	75
76	2005	50,059	355	1.37	68,581	76
77	2006	97,332	364	1.34	130,425	77
78	2007	405,096	382	1.28	518,523	78
79	2008	792,951	398	1.23	975,330	79
80	2009	536,325	389	1.25	670,406	80
81	2010	843,268	399	1.22	1,028,787	81
82	2011	827,878	411	1.19	985,175	82
83	2012	6,184,289	422	1.16	7,173,775	83
84	2013	4,414,353	431	1.13	4,988,219	84
85	2014	10,784,115	440	1.11	11,970,368	85
86	2015	4,396,643	442	1.10	4,836,307	86
87	2016	5,763,078	447	1.09	6,281,755	87
88	2017	970,673	465	1.05	1,019,207	88
89	2018	4,841,900	481	1.01	4,890,319	89
90	2019	0	488	1.00	0	90
91	Total	$ 59,652,388			$ 85,853,662	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 390.2 - Leasehold Structures and Improvements

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	19	25.68	$ 0	1
2	1931	0	17	28.71	0	2
3	1932	0	16	30.50	0	3
4	1933	0	17	28.71	0	4
5	1934	0	19	25.68	0	5
6	1935	0	18	27.11	0	6
7	1936	0	19	25.68	0	7
8	1937	0	20	24.40	0	8
9	1938	0	20	24.40	0	9
10	1939	0	20	24.40	0	10
11	1940	0	20	24.40	0	11
12	1941	0	22	22.18	0	12
13	1942	0	23	21.22	0	13
14	1943	0	23	21.22	0	14
15	1944	0	24	20.33	0	15
16	1945	0	24	20.33	0	16
17	1946	0	27	18.07	0	17
18	1947	0	32	15.25	0	18
19	1948	0	36	13.56	0	19
20	1949	0	37	13.19	0	20
21	1950	0	39	12.51	0	21
22	1951	0	42	11.62	0	22
23	1952	0	44	11.09	0	23
24	1953	0	44	11.09	0	24
25	1954	0	46	10.61	0	25
26	1955	0	48	10.17	0	26
27	1956	0	52	9.38	0	27
28	1957	0	55	8.87	0	28
29	1958	0	57	8.56	0	29
30	1959	0	58	8.41	0	30
31	1960	0	59	8.27	0	31
32	1961	0	58	8.41	0	32
33	1962	0	59	8.27	0	33
34	1963	0	60	8.13	0	34
35	1964	0	61	8.00	0	35
36	1965	0	64	7.63	0	36
37	1966	0	65	7.51	0	37
38	1967	0	67	7.28	0	38
39	1968	0	71	6.87	0	39
40	1969	0	75	6.51	0	40
41	1970	0	79	6.18	0	41
42	1971	0	87	5.61	0	42
43	1972	0	93	5.25	0	43
44	1973	0	100	4.88	0	44
45	1974	0	118	4.14	0	45
46	1975	0	133	3.67	0	46
47	1976	0	138	3.54	0	47
48	1977	0	148	3.30	0	48
49	1978	0	161	3.03	0	49
50	1979	19,087	177	2.76	52,680	50
51	1980	0	194	2.52	0	51
52	1981	0	204	2.39	0	52
53	1982	0	207	2.36	0	53
54	1983	0	215	2.27	0	54
55	1984	0	224	2.18	0	55
56	1985	0	226	2.16	0	56
57	1986	0	231	2.11	0	57
58	1987	0	232	2.10	0	58
59	1988	0	233	2.09	0	59
60	1989	0	232	2.10	0	60
61	1990	0	237	2.06	0	61
62	1991	0	233	2.09	0	62
63	1992	0	238	2.05	0	63
64	1993	0	250	1.95	0	64
65	1994	0	261	1.87	0	65
66	1995	0	265	1.84	0	66
67	1996	0	176	2.77	0	67
68	1997	9,419	282	1.73	16,295	68
69	1998	0	285	1.71	0	69
70	1999	0	287	1.70	0	70
71	2000	0	295	1.65	0	71
72	2001	0	303	1.61	0	72
73	2002	0	310	1.57	0	73
74	2003	0	320	1.53	0	74
75	2004	0	342	1.43	0	75
76	2005	0	355	1.37	0	76
77	2006	0	364	1.34	0	77
78	2007	0	382	1.28	0	78
79	2008	0	398	1.23	0	79
80	2009	0	389	1.25	0	80
81	2010	0	399	1.22	0	81
82	2011	0	411	1.19	0	82
83	2012	0	422	1.16	0	83
84	2013	0	431	1.13	0	84
85	2014	0	440	1.11	0	85
86	2015	0	442	1.10	0	86
87	2016	0	447	1.09	0	87
88	2017	21,000	465	1.05	22,050	88
89	2018	78,545	481	1.01	79,330	89
90	2019	0	488	1.00	0	90
91	Total	$ 128,051			$ 170,355	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 391 - Office Furniture and Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	11	42.55	$ 0	1
2	1931	0	11	42.55	0	2
3	1932	0	11	42.55	0	3
4	1933	0	11	42.55	0	4
5	1934	0	11	42.55	0	5
6	1935	0	11	42.55	0	6
7	1936	0	12	39.00	0	7
8	1937	0	13	36.00	0	8
9	1938	0	13	36.00	0	9
10	1939	0	13	36.00	0	10
11	1940	0	13	36.00	0	11
12	1941	0	13	36.00	0	12
13	1942	0	15	31.20	0	13
14	1943	0	15	31.20	0	14
15	1944	0	15	31.20	0	15
16	1945	0	16	29.25	0	16
17	1946	0	20	23.40	0	17
18	1947	0	23	20.35	0	18
19	1948	0	26	18.00	0	19
20	1949	0	26	18.00	0	20
21	1950	0	27	17.33	0	21
22	1951	0	29	16.14	0	22
23	1952	0	31	15.10	0	23
24	1953	0	33	14.18	0	24
25	1954	0	34	13.76	0	25
26	1955	0	36	13.00	0	26
27	1956	0	39	12.00	0	27
28	1957	0	41	11.41	0	28
29	1958	0	42	11.14	0	29
30	1959	0	45	10.40	0	30
31	1960	0	46	10.17	0	31
32	1961	0	51	9.18	0	32
33	1962	0	53	8.83	0	33
34	1963	0	55	8.51	0	34
35	1964	0	57	8.21	0	35
36	1965	0	60	7.80	0	36
37	1966	0	62	7.55	0	37
38	1967	0	66	7.09	0	38
39	1968	0	70	6.69	0	39
40	1969	0	74	6.32	0	40
41	1970	0	81	5.78	0	41
42	1971	0	87	5.38	0	42
43	1972	0	94	4.98	0	43
44	1973	0	100	4.68	0	44
45	1974	0	109	4.29	0	45
46	1975	0	123	3.80	0	46
47	1976	0	130	3.60	0	47
48	1977	0	141	3.32	0	48
49	1978	0	151	3.10	0	49
50	1979	0	164	2.85	0	50
51	1980	0	178	2.63	0	51
52	1981	0	186	2.52	0	52
53	1982	0	203	2.31	0	53
54	1983	0	209	2.24	0	54
55	1984	0	212	2.21	0	55
56	1985	0	211	2.22	0	56
57	1986	0	218	2.15	0	57
58	1987	0	226	2.07	0	58
59	1988	0	219	2.14	0	59
60	1989	0	213	2.20	0	60
61	1990	0	228	2.05	0	61
62	1991	0	242	1.93	0	62
63	1992	0	249	1.88	0	63
64	1993	0	260	1.80	0	64
65	1994	0	257	1.82	0	65
66	1995	0	246	1.90	0	66
67	1996	0	250	1.87	0	67
68	1997	0	251	1.86	0	68
69	1998	0	254	1.84	0	69
70	1999	0	261	1.79	0	70
71	2000	0	268	1.75	0	71
72	2001	0	280	1.67	0	72
73	2002	495,406	289	1.62	802,558	73
74	2003	12,036	293	1.60	19,258	74
75	2004	187,663	298	1.57	294,631	75
76	2005	8,828	303	1.54	13,595	76
77	2006	140,745	305	1.53	215,340	77
78	2007	1,193,984	317	1.48	1,767,096	78
79	2008	206,478	337	1.39	287,004	79
80	2009	555,580	359	1.30	722,254	80
81	2010	266,230	375	1.25	332,788	81
82	2011	570,548	387	1.21	690,363	82
83	2012	3,136	405	1.16	3,638	83
84	2013	94,153	412	1.14	107,334	84
85	2014	322,072	427	1.10	354,279	85
86	2015	630,206	429	1.09	686,925	86
87	2016	222,188	440	1.06	235,519	87
88	2017	102,534	449	1.04	106,635	88
89	2018	349,411	468	1.00	349,411	89
90	2019	0	468	1.00	0	90
91	Total	$ 5,361,198			$ 6,988,628	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 391.1 - Computer Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	11	42.55	$ 0	1
2	1931	0	11	42.55	0	2
3	1932	0	11	42.55	0	3
4	1933	0	11	42.55	0	4
5	1934	0	11	42.55	0	5
6	1935	0	11	42.55	0	6
7	1936	0	12	39.00	0	7
8	1937	0	13	36.00	0	8
9	1938	0	13	36.00	0	9
10	1939	0	13	36.00	0	10
11	1940	0	13	36.00	0	11
12	1941	0	13	36.00	0	12
13	1942	0	15	31.20	0	13
14	1943	0	15	31.20	0	14
15	1944	0	15	31.20	0	15
16	1945	0	16	29.25	0	16
17	1946	0	20	23.40	0	17
18	1947	0	23	20.35	0	18
19	1948	0	26	18.00	0	19
20	1949	0	26	18.00	0	20
21	1950	0	27	17.33	0	21
22	1951	0	29	16.14	0	22
23	1952	0	31	15.10	0	23
24	1953	0	33	14.18	0	24
25	1954	0	34	13.76	0	25
26	1955	0	36	13.00	0	26
27	1956	0	39	12.00	0	27
28	1957	0	41	11.41	0	28
29	1958	0	42	11.14	0	29
30	1959	0	45	10.40	0	30
31	1960	0	46	10.17	0	31
32	1961	0	51	9.18	0	32
33	1962	0	53	8.83	0	33
34	1963	0	55	8.51	0	34
35	1964	0	57	8.21	0	35
36	1965	0	60	7.80	0	36
37	1966	0	62	7.55	0	37
38	1967	0	66	7.09	0	38
39	1968	0	70	6.69	0	39
40	1969	0	74	6.32	0	40
41	1970	0	81	5.78	0	41
42	1971	0	87	5.38	0	42
43	1972	0	94	4.98	0	43
44	1973	0	100	4.68	0	44
45	1974	0	109	4.29	0	45
46	1975	0	123	3.80	0	46
47	1976	0	130	3.60	0	47
48	1977	0	141	3.32	0	48
49	1978	0	151	3.10	0	49
50	1979	0	164	2.85	0	50
51	1980	0	178	2.63	0	51
52	1981	0	186	2.52	0	52
53	1982	0	203	2.31	0	53
54	1983	0	209	2.24	0	54
55	1984	0	212	2.21	0	55
56	1985	0	211	2.22	0	56
57	1986	0	218	2.15	0	57
58	1987	0	226	2.07	0	58
59	1988	0	219	2.14	0	59
60	1989	0	213	2.20	0	60
61	1990	0	228	2.05	0	61
62	1991	0	242	1.93	0	62
63	1992	0	249	1.88	0	63
64	1993	0	260	1.80	0	64
65	1994	0	257	1.82	0	65
66	1995	0	246	1.90	0	66
67	1996	0	250	1.87	0	67
68	1997	0	251	1.86	0	68
69	1998	0	254	1.84	0	69
70	1999	0	261	1.79	0	70
71	2000	0	268	1.75	0	71
72	2001	0	280	1.67	0	72
73	2002	0	289	1.62	0	73
74	2003	0	293	1.60	0	74
75	2004	0	298	1.57	0	75
76	2005	0	303	1.54	0	76
77	2006	0	305	1.53	0	77
78	2007	0	317	1.48	0	78
79	2008	0	337	1.39	0	79
80	2009	0	359	1.30	0	80
81	2010	0	375	1.25	0	81
82	2011	0	387	1.21	0	82
83	2012	0	405	1.16	0	83
84	2013	0	412	1.14	0	84
85	2014	696,353	427	1.10	765,988	85
86	2015	2,144,844	429	1.09	2,337,880	86
87	2016	3,771,894	440	1.06	3,998,208	87
88	2017	4,438,873	449	1.04	4,616,428	88
89	2018	3,991,101	468	1.00	3,991,101	89
90	2019	0	468	1.00	0	90
91	Total	$ 15,043,065			$ 15,709,605	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 392.1 - Transportation Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	23.55	$ 0	1
2	1931	0	20	25.90	0	2
3	1932	0	19	27.26	0	3
4	1933	0	19	27.26	0	4
5	1934	0	20	25.90	0	5
6	1935	0	21	24.67	0	6
7	1936	0	21	24.67	0	7
8	1937	0	23	22.52	0	8
9	1938	0	23	22.52	0	9
10	1939	0	23	22.52	0	10
11	1940	0	24	21.58	0	11
12	1941	0	25	20.72	0	12
13	1942	0	28	18.50	0	13
14	1943	0	29	17.86	0	14
15	1944	0	29	17.86	0	15
16	1945	0	29	17.86	0	16
17	1946	0	34	15.24	0	17
18	1947	0	37	14.00	0	18
19	1948	0	39	13.28	0	19
20	1949	0	40	12.95	0	20
21	1950	0	42	12.33	0	21
22	1951	0	45	11.51	0	22
23	1952	0	46	11.26	0	23
24	1953	0	49	10.57	0	24
25	1954	0	49	10.57	0	25
26	1955	0	51	10.16	0	26
27	1956	0	55	9.42	0	27
28	1957	0	59	8.78	0	28
29	1958	0	62	8.35	0	29
30	1959	0	64	8.09	0	30
31	1960	0	65	7.97	0	31
32	1961	0	67	7.73	0	32
33	1962	0	67	7.73	0	33
34	1963	0	68	7.62	0	34
35	1964	0	70	7.40	0	35
36	1965	0	71	7.30	0	36
37	1966	0	73	7.10	0	37
38	1967	0	76	6.82	0	38
39	1968	0	80	6.48	0	39
40	1969	0	84	6.17	0	40
41	1970	0	88	5.89	0	41
42	1971	0	93	5.57	0	42
43	1972	0	95	5.45	0	43
44	1973	0	100	5.18	0	44
45	1974	0	117	4.43	0	45
46	1975	0	141	3.67	0	46
47	1976	0	153	3.39	0	47
48	1977	0	164	3.16	0	48
49	1978	0	178	2.91	0	49
50	1979	0	197	2.63	0	50
51	1980	0	222	2.33	0	51
52	1981	0	246	2.11	0	52
53	1982	0	263	1.97	0	53
54	1983	0	269	1.93	0	54
55	1984	0	273	1.90	0	55
56	1985	0	276	1.88	0	56
57	1986	0	280	1.85	0	57
58	1987	0	286	1.81	0	58
59	1988	0	295	1.76	0	59
60	1989	0	281	1.84	0	60
61	1990	0	298	1.74	0	61
62	1991	0	320	1.62	0	62
63	1992	0	316	1.64	0	63
64	1993	0	324	1.60	0	64
65	1994	0	331	1.56	0	65
66	1995	0	333	1.56	0	66
67	1996	0	336	1.54	0	67
68	1997	0	351	1.48	0	68
69	1998	0	380	1.36	0	69
70	1999	0	385	1.35	0	70
71	2000	0	389	1.33	0	71
72	2001	0	390	1.33	0	72
73	2002	0	395	1.31	0	73
74	2003	0	401	1.29	0	74
75	2004	0	414	1.25	0	75
76	2005	0	439	1.18	0	76
77	2006	0	457	1.13	0	77
78	2007	568,627	469	1.10	625,490	78
79	2008	1,397,576	485	1.07	1,495,406	79
80	2009	2,700,769	501	1.03	2,781,792	80
81	2010	1,200,738	503	1.03	1,236,760	81
82	2011	5,060,886	516	1.00	5,060,886	82
83	2012	3,037,568	538	0.96	2,916,065	83
84	2013	4,444,643	551	0.94	4,177,964	84
85	2014	4,071,679	560	0.93	3,786,661	85
86	2015	4,370,262	567	0.91	3,976,938	86
87	2016	4,424,190	573	0.90	3,981,771	87
88	2017	4,656,517	578	0.90	4,190,865	88
89	2018	5,942,208	576	0.90	5,347,987	89
90	2019	0	518	1.00	0	90
91	Total	$ 41,875,663			$ 39,578,585	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 393 - Stores Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	23.55	$ 0	1
2	1931	0	20	25.90	0	2
3	1932	0	19	27.26	0	3
4	1933	0	19	27.26	0	4
5	1934	0	20	25.90	0	5
6	1935	0	21	24.67	0	6
7	1936	0	21	24.67	0	7
8	1937	0	23	22.52	0	8
9	1938	0	23	22.52	0	9
10	1939	0	23	22.52	0	10
11	1940	0	24	21.58	0	11
12	1941	0	25	20.72	0	12
13	1942	0	28	18.50	0	13
14	1943	0	29	17.86	0	14
15	1944	0	29	17.86	0	15
16	1945	0	29	17.86	0	16
17	1946	0	34	15.24	0	17
18	1947	0	37	14.00	0	18
19	1948	0	39	13.28	0	19
20	1949	0	40	12.95	0	20
21	1950	0	42	12.33	0	21
22	1951	0	45	11.51	0	22
23	1952	0	46	11.26	0	23
24	1953	0	49	10.57	0	24
25	1954	0	49	10.57	0	25
26	1955	0	51	10.16	0	26
27	1956	0	55	9.42	0	27
28	1957	0	59	8.78	0	28
29	1958	0	62	8.35	0	29
30	1959	0	64	8.09	0	30
31	1960	0	65	7.97	0	31
32	1961	0	67	7.73	0	32
33	1962	0	67	7.73	0	33
34	1963	0	68	7.62	0	34
35	1964	0	70	7.40	0	35
36	1965	0	71	7.30	0	36
37	1966	0	73	7.10	0	37
38	1967	0	76	6.82	0	38
39	1968	0	80	6.48	0	39
40	1969	0	84	6.17	0	40
41	1970	0	88	5.89	0	41
42	1971	0	93	5.57	0	42
43	1972	0	95	5.45	0	43
44	1973	0	100	5.18	0	44
45	1974	0	117	4.43	0	45
46	1975	0	141	3.67	0	46
47	1976	0	153	3.39	0	47
48	1977	0	164	3.16	0	48
49	1978	0	178	2.91	0	49
50	1979	0	197	2.63	0	50
51	1980	0	222	2.33	0	51
52	1981	0	246	2.11	0	52
53	1982	0	263	1.97	0	53
54	1983	0	269	1.93	0	54
55	1984	0	273	1.90	0	55
56	1985	0	276	1.88	0	56
57	1986	0	280	1.85	0	57
58	1987	0	286	1.81	0	58
59	1988	0	295	1.76	0	59
60	1989	0	281	1.84	0	60
61	1990	0	298	1.74	0	61
62	1991	0	320	1.62	0	62
63	1992	0	316	1.64	0	63
64	1993	0	324	1.60	0	64
65	1994	17,116	331	1.56	26,701	65
66	1995	0	333	1.56	0	66
67	1996	0	336	1.54	0	67
68	1997	41,959	351	1.48	62,099	68
69	1998	0	380	1.36	0	69
70	1999	50,326	385	1.35	67,940	70
71	2000	10,930	389	1.33	14,537	71
72	2001	4,375	390	1.33	5,819	72
73	2002	73,300	395	1.31	96,023	73
74	2003	0	401	1.29	0	74
75	2004	26,256	414	1.25	32,820	75
76	2005	64,821	439	1.18	76,489	76
77	2006	11,760	457	1.13	13,289	77
78	2007	0	469	1.10	0	78
79	2008	81,414	485	1.07	87,113	79
80	2009	0	501	1.03	0	80
81	2010	27,374	503	1.03	28,195	81
82	2011	45,503	516	1.00	45,503	82
83	2012	1,940	538	0.96	1,862	83
84	2013	41,240	551	0.94	38,766	84
85	2014	49,821	560	0.93	46,334	85
86	2015	69,873	567	0.91	63,584	86
87	2016	192,568	573	0.90	173,311	87
88	2017	11,437	578	0.90	10,293	88
89	2018	117,113	576	0.90	105,402	89
90	2019	0	518	1.00	0	90
91	Total	$ 939,126			$ 996,080	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 394 - Tools, Shop and Garage Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	23.55	$ 0	1
2	1931	0	20	25.90	0	2
3	1932	0	19	27.26	0	3
4	1933	0	19	27.26	0	4
5	1934	0	20	25.90	0	5
6	1935	0	21	24.67	0	6
7	1936	0	21	24.67	0	7
8	1937	0	23	22.52	0	8
9	1938	0	23	22.52	0	9
10	1939	0	23	22.52	0	10
11	1940	0	24	21.58	0	11
12	1941	0	25	20.72	0	12
13	1942	0	28	18.50	0	13
14	1943	0	29	17.86	0	14
15	1944	0	29	17.86	0	15
16	1945	0	29	17.86	0	16
17	1946	0	34	15.24	0	17
18	1947	0	37	14.00	0	18
19	1948	0	39	13.28	0	19
20	1949	0	40	12.95	0	20
21	1950	0	42	12.33	0	21
22	1951	0	45	11.51	0	22
23	1952	0	46	11.26	0	23
24	1953	0	49	10.57	0	24
25	1954	0	49	10.57	0	25
26	1955	0	51	10.16	0	26
27	1956	0	55	9.42	0	27
28	1957	0	59	8.78	0	28
29	1958	0	62	8.35	0	29
30	1959	0	64	8.09	0	30
31	1960	0	65	7.97	0	31
32	1961	0	67	7.73	0	32
33	1962	0	67	7.73	0	33
34	1963	0	68	7.62	0	34
35	1964	0	70	7.40	0	35
36	1965	0	71	7.30	0	36
37	1966	0	73	7.10	0	37
38	1967	0	76	6.82	0	38
39	1968	0	80	6.48	0	39
40	1969	0	84	6.17	0	40
41	1970	0	88	5.89	0	41
42	1971	0	93	5.57	0	42
43	1972	0	95	5.45	0	43
44	1973	0	100	5.18	0	44
45	1974	0	117	4.43	0	45
46	1975	0	141	3.67	0	46
47	1976	0	153	3.39	0	47
48	1977	0	164	3.16	0	48
49	1978	0	178	2.91	0	49
50	1979	0	197	2.63	0	50
51	1980	0	222	2.33	0	51
52	1981	0	246	2.11	0	52
53	1982	0	263	1.97	0	53
54	1983	0	269	1.93	0	54
55	1984	0	273	1.90	0	55
56	1985	0	276	1.88	0	56
57	1986	0	280	1.85	0	57
58	1987	0	286	1.81	0	58
59	1988	0	295	1.76	0	59
60	1989	0	281	1.84	0	60
61	1990	0	298	1.74	0	61
62	1991	0	320	1.62	0	62
63	1992	0	316	1.64	0	63
64	1993	0	324	1.60	0	64
65	1994	0	331	1.56	0	65
66	1995	0	333	1.56	0	66
67	1996	0	336	1.54	0	67
68	1997	0	351	1.48	0	68
69	1998	0	380	1.36	0	69
70	1999	0	385	1.35	0	70
71	2000	0	389	1.33	0	71
72	2001	0	390	1.33	0	72
73	2002	0	395	1.31	0	73
74	2003	0	401	1.29	0	74
75	2004	225,246	414	1.25	281,558	75
76	2005	422,568	439	1.18	498,630	76
77	2006	422,962	457	1.13	477,947	77
78	2007	423,466	469	1.10	465,813	78
79	2008	343,920	485	1.07	367,994	79
80	2009	1,461,053	501	1.03	1,504,885	80
81	2010	395,084	503	1.03	406,937	81
82	2011	626,663	516	1.00	626,663	82
83	2012	481,562	538	0.96	462,300	83
84	2013	754,983	551	0.94	709,684	84
85	2014	1,043,422	560	0.93	970,382	85
86	2015	1,302,683	567	0.91	1,185,442	86
87	2016	1,188,647	573	0.90	1,069,782	87
88	2017	1,708,014	578	0.90	1,537,213	88
89	2018	1,327,044	576	0.90	1,194,340	89
90	2019	26,903	518	1.00	26,903	90
91	Total	$ 12,154,220			$ 11,786,473	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 395 - Laboratory Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	11	42.55	$ 0	1
2	1931	0	11	42.55	0	2
3	1932	0	11	42.55	0	3
4	1933	0	11	42.55	0	4
5	1934	0	11	42.55	0	5
6	1935	0	11	42.55	0	6
7	1936	0	12	39.00	0	7
8	1937	0	13	36.00	0	8
9	1938	0	13	36.00	0	9
10	1939	0	13	36.00	0	10
11	1940	0	13	36.00	0	11
12	1941	0	13	36.00	0	12
13	1942	0	15	31.20	0	13
14	1943	0	15	31.20	0	14
15	1944	0	15	31.20	0	15
16	1945	0	16	29.25	0	16
17	1946	0	20	23.40	0	17
18	1947	0	23	20.35	0	18
19	1948	0	26	18.00	0	19
20	1949	0	26	18.00	0	20
21	1950	0	27	17.33	0	21
22	1951	0	29	16.14	0	22
23	1952	0	31	15.10	0	23
24	1953	0	33	14.18	0	24
25	1954	0	34	13.76	0	25
26	1955	0	36	13.00	0	26
27	1956	0	39	12.00	0	27
28	1957	0	41	11.41	0	28
29	1958	0	42	11.14	0	29
30	1959	0	45	10.40	0	30
31	1960	0	46	10.17	0	31
32	1961	0	51	9.18	0	32
33	1962	0	53	8.83	0	33
34	1963	0	55	8.51	0	34
35	1964	0	57	8.21	0	35
36	1965	0	60	7.80	0	36
37	1966	0	62	7.55	0	37
38	1967	0	66	7.09	0	38
39	1968	0	70	6.69	0	39
40	1969	0	74	6.32	0	40
41	1970	0	81	5.78	0	41
42	1971	0	87	5.38	0	42
43	1972	0	94	4.98	0	43
44	1973	0	100	4.68	0	44
45	1974	0	109	4.29	0	45
46	1975	0	123	3.80	0	46
47	1976	0	130	3.60	0	47
48	1977	0	141	3.32	0	48
49	1978	0	151	3.10	0	49
50	1979	0	164	2.85	0	50
51	1980	0	178	2.63	0	51
52	1981	0	186	2.52	0	52
53	1982	0	203	2.31	0	53
54	1983	0	209	2.24	0	54
55	1984	0	212	2.21	0	55
56	1985	0	211	2.22	0	56
57	1986	0	218	2.15	0	57
58	1987	0	226	2.07	0	58
59	1988	0	219	2.14	0	59
60	1989	0	213	2.20	0	60
61	1990	0	228	2.05	0	61
62	1991	0	242	1.93	0	62
63	1992	0	249	1.88	0	63
64	1993	0	260	1.80	0	64
65	1994	20,488	257	1.82	37,288	65
66	1995	0	246	1.90	0	66
67	1996	1,803	250	1.87	3,372	67
68	1997	0	251	1.86	0	68
69	1998	1,707	254	1.84	3,141	69
70	1999	142,885	261	1.79	255,764	70
71	2000	0	268	1.75	0	71
72	2001	0	280	1.67	0	72
73	2002	59,897	289	1.62	97,033	73
74	2003	1,552	293	1.60	2,483	74
75	2004	2,421	298	1.57	3,801	75
76	2005	0	303	1.54	0	76
77	2006	2,466	305	1.53	3,773	77
78	2007	42,853	317	1.48	63,422	78
79	2008	2,421	337	1.39	3,365	79
80	2009	336	359	1.30	437	80
81	2010	8,738	375	1.25	10,923	81
82	2011	32,281	387	1.21	39,060	82
83	2012	62,679	405	1.16	72,708	83
84	2013	0	412	1.14	0	84
85	2014	99,164	427	1.10	109,080	85
86	2015	0	429	1.09	0	86
87	2016	19,722	440	1.06	20,905	87
88	2017	52,425	449	1.04	54,522	88
89	2018	3,349	468	1.00	3,349	89
90	2019	0	468	1.00	0	90
91	Total	$ 557,187			$ 784,426	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 396 - Power Operated Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	23.55	$ 0	1
2	1931	0	20	25.90	0	2
3	1932	0	19	27.26	0	3
4	1933	0	19	27.26	0	4
5	1934	0	20	25.90	0	5
6	1935	0	21	24.67	0	6
7	1936	0	21	24.67	0	7
8	1937	0	23	22.52	0	8
9	1938	0	23	22.52	0	9
10	1939	0	23	22.52	0	10
11	1940	0	24	21.58	0	11
12	1941	0	25	20.72	0	12
13	1942	0	28	18.50	0	13
14	1943	0	29	17.86	0	14
15	1944	0	29	17.86	0	15
16	1945	0	29	17.86	0	16
17	1946	0	34	15.24	0	17
18	1947	0	37	14.00	0	18
19	1948	0	39	13.28	0	19
20	1949	0	40	12.95	0	20
21	1950	0	42	12.33	0	21
22	1951	0	45	11.51	0	22
23	1952	0	46	11.26	0	23
24	1953	0	49	10.57	0	24
25	1954	0	49	10.57	0	25
26	1955	0	51	10.16	0	26
27	1956	0	55	9.42	0	27
28	1957	0	59	8.78	0	28
29	1958	0	62	8.35	0	29
30	1959	0	64	8.09	0	30
31	1960	0	65	7.97	0	31
32	1961	0	67	7.73	0	32
33	1962	0	67	7.73	0	33
34	1963	0	68	7.62	0	34
35	1964	0	70	7.40	0	35
36	1965	0	71	7.30	0	36
37	1966	0	73	7.10	0	37
38	1967	0	76	6.82	0	38
39	1968	0	80	6.48	0	39
40	1969	0	84	6.17	0	40
41	1970	0	88	5.89	0	41
42	1971	0	93	5.57	0	42
43	1972	0	95	5.45	0	43
44	1973	0	100	5.18	0	44
45	1974	0	117	4.43	0	45
46	1975	0	141	3.67	0	46
47	1976	0	153	3.39	0	47
48	1977	0	164	3.16	0	48
49	1978	0	178	2.91	0	49
50	1979	0	197	2.63	0	50
51	1980	0	222	2.33	0	51
52	1981	0	246	2.11	0	52
53	1982	0	263	1.97	0	53
54	1983	0	269	1.93	0	54
55	1984	0	273	1.90	0	55
56	1985	0	276	1.88	0	56
57	1986	0	280	1.85	0	57
58	1987	0	286	1.81	0	58
59	1988	0	295	1.76	0	59
60	1989	0	281	1.84	0	60
61	1990	0	298	1.74	0	61
62	1991	0	320	1.62	0	62
63	1992	0	316	1.64	0	63
64	1993	0	324	1.60	0	64
65	1994	0	331	1.56	0	65
66	1995	0	333	1.56	0	66
67	1996	0	336	1.54	0	67
68	1997	0	351	1.48	0	68
69	1998	0	380	1.36	0	69
70	1999	0	385	1.35	0	70
71	2000	0	389	1.33	0	71
72	2001	0	390	1.33	0	72
73	2002	0	395	1.31	0	73
74	2003	0	401	1.29	0	74
75	2004	0	414	1.25	0	75
76	2005	503,729	439	1.18	594,400	76
77	2006	843,457	457	1.13	953,106	77
78	2007	818,254	469	1.10	900,079	78
79	2008	1,204,692	485	1.07	1,289,020	79
80	2009	598,438	501	1.03	616,391	80
81	2010	1,032,051	503	1.03	1,063,013	81
82	2011	613,696	516	1.00	613,696	82
83	2012	388,221	538	0.96	372,692	83
84	2013	272,896	551	0.94	256,522	84
85	2014	235,577	560	0.93	219,087	85
86	2015	760,294	567	0.91	691,868	86
87	2016	608,650	573	0.90	547,785	87
88	2017	283,390	578	0.90	255,051	88
89	2018	836,655	576	0.90	752,990	89
90	2019	6,861	518	1.00	6,861	90
91	Total	$ 9,006,861			$ 9,132,561	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 397.1 - Communication Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	15	32.07	$ 0	1
2	1931	0	15	32.07	0	2
3	1932	0	15	32.07	0	3
4	1933	0	15	32.07	0	4
5	1934	0	15	32.07	0	5
6	1935	0	15	32.07	0	6
7	1936	0	15	32.07	0	7
8	1937	0	17	28.29	0	8
9	1938	0	17	28.29	0	9
10	1939	0	17	28.29	0	10
11	1940	0	17	28.29	0	11
12	1941	0	18	26.72	0	12
13	1942	0	19	25.32	0	13
14	1943	0	19	25.32	0	14
15	1944	0	19	25.32	0	15
16	1945	0	19	25.32	0	16
17	1946	0	21	22.90	0	17
18	1947	0	24	20.04	0	18
19	1948	0	26	18.50	0	19
20	1949	0	28	17.18	0	20
21	1950	0	30	16.03	0	21
22	1951	0	31	15.52	0	22
23	1952	0	33	14.58	0	23
24	1953	0	34	14.15	0	24
25	1954	0	36	13.36	0	25
26	1955	0	37	13.00	0	26
27	1956	0	39	12.33	0	27
28	1957	0	41	11.73	0	28
29	1958	0	42	11.45	0	29
30	1959	0	45	10.69	0	30
31	1960	0	46	10.46	0	31
32	1961	0	49	9.82	0	32
33	1962	0	51	9.43	0	33
34	1963	0	52	9.25	0	34
35	1964	0	54	8.91	0	35
36	1965	0	57	8.44	0	36
37	1966	0	58	8.29	0	37
38	1967	0	62	7.76	0	38
39	1968	0	64	7.52	0	39
40	1969	0	69	6.97	0	40
41	1970	0	78	6.17	0	41
42	1971	0	88	5.47	0	42
43	1972	0	95	5.06	0	43
44	1973	0	100	4.81	0	44
45	1974	0	109	4.41	0	45
46	1975	0	122	3.94	0	46
47	1976	0	131	3.67	0	47
48	1977	0	142	3.39	0	48
49	1978	0	151	3.19	0	49
50	1979	0	160	3.01	0	50
51	1980	0	170	2.83	0	51
52	1981	0	185	2.60	0	52
53	1982	0	206	2.33	0	53
54	1983	0	218	2.21	0	54
55	1984	0	220	2.19	0	55
56	1985	0	214	2.25	0	56
57	1986	0	215	2.24	0	57
58	1987	0	216	2.23	0	58
59	1988	0	215	2.24	0	59
60	1989	0	214	2.25	0	60
61	1990	0	220	2.19	0	61
62	1991	0	225	2.14	0	62
63	1992	0	232	2.07	0	63
64	1993	0	236	2.04	0	64
65	1994	0	239	2.01	0	65
66	1995	0	247	1.95	0	66
67	1996	0	254	1.89	0	67
68	1997	0	257	1.87	0	68
69	1998	0	265	1.82	0	69
70	1999	0	275	1.75	0	70
71	2000	0	285	1.69	0	71
72	2001	0	299	1.61	0	72
73	2002	0	309	1.56	0	73
74	2003	0	318	1.51	0	74
75	2004	0	327	1.47	0	75
76	2005	0	337	1.43	0	76
77	2006	49,609	345	1.39	68,957	77
78	2007	16,728	354	1.36	22,750	78
79	2008	30,017	365	1.32	39,622	79
80	2009	16,980	382	1.26	21,395	80
81	2010	156,464	406	1.18	184,628	81
82	2011	260,259	416	1.16	301,900	82
83	2012	548,932	424	1.13	620,293	83
84	2013	22,458	429	1.12	25,153	84
85	2014	577,846	437	1.10	635,631	85
86	2015	60,221	445	1.08	65,039	86
87	2016	84,327	449	1.07	90,230	87
88	2017	107,006	473	1.02	109,146	88
89	2018	129,780	481	1.00	129,780	89
90	2019	0	481	1.00	0	90
91	Total	$ 2,060,627			$ 2,314,524	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 397.2 - Telemetering Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	15	32.07	$ 0	1
2	1931	0	15	32.07	0	2
3	1932	0	15	32.07	0	3
4	1933	0	15	32.07	0	4
5	1934	0	15	32.07	0	5
6	1935	0	15	32.07	0	6
7	1936	0	15	32.07	0	7
8	1937	0	17	28.29	0	8
9	1938	0	17	28.29	0	9
10	1939	0	17	28.29	0	10
11	1940	0	17	28.29	0	11
12	1941	0	18	26.72	0	12
13	1942	0	19	25.32	0	13
14	1943	0	19	25.32	0	14
15	1944	0	19	25.32	0	15
16	1945	0	19	25.32	0	16
17	1946	0	21	22.90	0	17
18	1947	0	24	20.04	0	18
19	1948	0	26	18.50	0	19
20	1949	0	28	17.18	0	20
21	1950	0	30	16.03	0	21
22	1951	0	31	15.52	0	22
23	1952	0	33	14.58	0	23
24	1953	0	34	14.15	0	24
25	1954	0	36	13.36	0	25
26	1955	0	37	13.00	0	26
27	1956	0	39	12.33	0	27
28	1957	0	41	11.73	0	28
29	1958	0	42	11.45	0	29
30	1959	0	45	10.69	0	30
31	1960	0	46	10.46	0	31
32	1961	0	49	9.82	0	32
33	1962	0	51	9.43	0	33
34	1963	0	52	9.25	0	34
35	1964	0	54	8.91	0	35
36	1965	0	57	8.44	0	36
37	1966	0	58	8.29	0	37
38	1967	0	62	7.76	0	38
39	1968	0	64	7.52	0	39
40	1969	0	69	6.97	0	40
41	1970	0	78	6.17	0	41
42	1971	0	88	5.47	0	42
43	1972	0	95	5.06	0	43
44	1973	0	100	4.81	0	44
45	1974	0	109	4.41	0	45
46	1975	0	122	3.94	0	46
47	1976	0	131	3.67	0	47
48	1977	0	142	3.39	0	48
49	1978	0	151	3.19	0	49
50	1979	0	160	3.01	0	50
51	1980	0	170	2.83	0	51
52	1981	0	185	2.60	0	52
53	1982	0	206	2.33	0	53
54	1983	0	218	2.21	0	54
55	1984	0	220	2.19	0	55
56	1985	0	214	2.25	0	56
57	1986	0	215	2.24	0	57
58	1987	0	216	2.23	0	58
59	1988	0	215	2.24	0	59
60	1989	0	214	2.25	0	60
61	1990	0	220	2.19	0	61
62	1991	0	225	2.14	0	62
63	1992	0	232	2.07	0	63
64	1993	0	236	2.04	0	64
65	1994	0	239	2.01	0	65
66	1995	0	247	1.95	0	66
67	1996	0	254	1.89	0	67
68	1997	0	257	1.87	0	68
69	1998	0	265	1.82	0	69
70	1999	0	275	1.75	0	70
71	2000	0	285	1.69	0	71
72	2001	0	299	1.61	0	72
73	2002	0	309	1.56	0	73
74	2003	0	318	1.51	0	74
75	2004	0	327	1.47	0	75
76	2005	0	337	1.43	0	76
77	2006	0	345	1.39	0	77
78	2007	0	354	1.36	0	78
79	2008	0	365	1.32	0	79
80	2009	72,124	382	1.26	90,876	80
81	2010	51,393	406	1.18	60,644	81
82	2011	31,058	416	1.16	36,027	82
83	2012	0	424	1.13	0	83
84	2013	0	429	1.12	0	84
85	2014	0	437	1.10	0	85
86	2015	0	445	1.08	0	86
87	2016	9,312	449	1.07	9,964	87
88	2017	0	473	1.02	0	88
89	2018	0	481	1.00	0	89
90	2019	0	481	1.00	0	90
91	Total	$ 163,887			$ 197,511	91

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 398 - Miscellaneous Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	15	32.07	$ 0	1
2	1931	0	15	32.07	0	2
3	1932	0	15	32.07	0	3
4	1933	0	15	32.07	0	4
5	1934	0	15	32.07	0	5
6	1935	0	15	32.07	0	6
7	1936	0	15	32.07	0	7
8	1937	0	17	28.29	0	8
9	1938	0	17	28.29	0	9
10	1939	0	17	28.29	0	10
11	1940	0	17	28.29	0	11
12	1941	0	18	26.72	0	12
13	1942	0	19	25.32	0	13
14	1943	0	19	25.32	0	14
15	1944	0	19	25.32	0	15
16	1945	0	19	25.32	0	16
17	1946	0	21	22.90	0	17
18	1947	0	24	20.04	0	18
19	1948	0	26	18.50	0	19
20	1949	0	28	17.18	0	20
21	1950	0	30	16.03	0	21
22	1951	0	31	15.52	0	22
23	1952	0	33	14.58	0	23
24	1953	0	34	14.15	0	24
25	1954	0	36	13.36	0	25
26	1955	0	37	13.00	0	26
27	1956	0	39	12.33	0	27
28	1957	0	41	11.73	0	28
29	1958	0	42	11.45	0	29
30	1959	0	45	10.69	0	30
31	1960	0	46	10.46	0	31
32	1961	0	49	9.82	0	32
33	1962	0	51	9.43	0	33
34	1963	0	52	9.25	0	34
35	1964	0	54	8.91	0	35
36	1965	0	57	8.44	0	36
37	1966	0	58	8.29	0	37
38	1967	0	62	7.76	0	38
39	1968	0	64	7.52	0	39
40	1969	0	69	6.97	0	40
41	1970	0	78	6.17	0	41
42	1971	0	88	5.47	0	42
43	1972	0	95	5.06	0	43
44	1973	0	100	4.81	0	44
45	1974	0	109	4.41	0	45
46	1975	0	122	3.94	0	46
47	1976	0	131	3.67	0	47
48	1977	0	142	3.39	0	48
49	1978	0	151	3.19	0	49
50	1979	0	160	3.01	0	50
51	1980	0	170	2.83	0	51
52	1981	0	185	2.60	0	52
53	1982	0	206	2.33	0	53
54	1983	0	218	2.21	0	54
55	1984	0	220	2.19	0	55
56	1985	0	214	2.25	0	56
57	1986	0	215	2.24	0	57
58	1987	0	216	2.23	0	58
59	1988	0	215	2.24	0	59
60	1989	0	214	2.25	0	60
61	1990	0	220	2.19	0	61
62	1991	0	225	2.14	0	62
63	1992	0	232	2.07	0	63
64	1993	0	236	2.04	0	64
65	1994	0	239	2.01	0	65
66	1995	0	247	1.95	0	66
67	1996	0	254	1.89	0	67
68	1997	0	257	1.87	0	68
69	1998	0	265	1.82	0	69
70	1999	0	275	1.75	0	70
71	2000	0	285	1.69	0	71
72	2001	0	299	1.61	0	72
73	2002	0	309	1.56	0	73
74	2003	0	318	1.51	0	74
75	2004	10,940	327	1.47	16,082	75
76	2005	37,775	337	1.43	54,018	76
77	2006	4,815	345	1.39	6,693	77
78	2007	46,258	354	1.36	62,911	78
79	2008	15,323	365	1.32	20,226	79
80	2009	27,715	382	1.26	34,921	80
81	2010	119,593	406	1.18	141,120	81
82	2011	103,655	416	1.16	120,240	82
83	2012	14,500	424	1.13	16,385	83
84	2013	66,876	429	1.12	74,901	84
85	2014	209,061	437	1.10	229,967	85
86	2015	132,791	445	1.08	143,414	86
87	2016	945,793	449	1.07	1,011,999	87
88	2017	146,606	473	1.02	149,538	88
89	2018	161,651	481	1.00	161,651	89
90	2019	0	481	1.00	0	90
91	Total	$ 2,043,352			$ 2,244,066	91
92	Grand Total	$ 3,700,355,785			$ 5,934,984,859	92

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

	Account 389 - Land and Land Rights					
Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	1	1.00	$ 0	1
2	1931	0	1	1.00	0	2
3	1932	0	1	1.00	0	3
4	1933	0	1	1.00	0	4
5	1934	0	1	1.00	0	5
6	1935	0	1	1.00	0	6
7	1936	0	1	1.00	0	7
8	1937	0	1	1.00	0	8
9	1938	0	1	1.00	0	9
10	1939	0	1	1.00	0	10
11	1940	0	1	1.00	0	11
12	1941	0	1	1.00	0	12
13	1942	0	1	1.00	0	13
14	1943	0	1	1.00	0	14
15	1944	0	1	1.00	0	15
16	1945	0	1	1.00	0	16
17	1946	0	1	1.00	0	17
18	1947	0	1	1.00	0	18
19	1948	0	1	1.00	0	19
20	1949	0	1	1.00	0	20
21	1950	0	1	1.00	0	21
22	1951	0	1	1.00	0	22
23	1952	0	1	1.00	0	23
24	1953	0	1	1.00	0	24
25	1954	0	1	1.00	0	25
26	1955	0	1	1.00	0	26
27	1956	0	1	1.00	0	27
28	1957	0	1	1.00	0	28
29	1958	0	1	1.00	0	29
30	1959	0	1	1.00	0	30
31	1960	0	1	1.00	0	31
32	1961	0	1	1.00	0	32
33	1962	0	1	1.00	0	33
34	1963	0	1	1.00	0	34
35	1964	0	1	1.00	0	35
36	1965	0	1	1.00	0	36
37	1966	0	1	1.00	0	37
38	1967	0	1	1.00	0	38
39	1968	0	1	1.00	0	39
40	1969	0	1	1.00	0	40
41	1970	0	1	1.00	0	41
42	1971	0	1	1.00	0	42
43	1972	0	1	1.00	0	43
44	1973	0	1	1.00	0	44
45	1974	0	1	1.00	0	45
46	1975	0	1	1.00	0	46
47	1976	0	1	1.00	0	47
48	1977	0	1	1.00	0	48
49	1978	0	1	1.00	0	49
50	1979	0	1	1.00	0	50
51	1980	0	1	1.00	0	51
52	1981	0	1	1.00	0	52
53	1982	0	1	1.00	0	53
54	1983	0	1	1.00	0	54
55	1984	0	1	1.00	0	55
56	1985	0	1	1.00	0	56
57	1986	0	1	1.00	0	57
58	1987	0	1	1.00	0	58
59	1988	0	1	1.00	0	59
60	1989	248,909	1	1.00	248,909	60
61	1990	0	1	1.00	0	61
62	1991	0	1	1.00	0	62
63	1992	0	1	1.00	0	63
64	1993	142,398	1	1.00	142,398	64
65	1994	0	1	1.00	0	65
66	1995	0	1	1.00	0	66
67	1996	0	1	1.00	0	67
68	1997	0	1	1.00	0	68
69	1998	0	1	1.00	0	69
70	1999	0	1	1.00	0	70
71	2000	0	1	1.00	0	71
72	2001	0	1	1.00	0	72
73	2002	0	1	1.00	0	73
74	2003	0	1	1.00	0	74
75	2004	0	1	1.00	0	75
76	2005	0	1	1.00	0	76
77	2006	0	1	1.00	0	77
78	2007	0	1	1.00	0	78
79	2008	0	1	1.00	0	79
80	2009	0	1	1.00	0	80
81	2010	0	1	1.00	0	81
82	2011	0	1	1.00	0	82
83	2012	0	1	1.00	0	83
84	2013	0	1	1.00	0	84
85	2014	3,825,399	1	1.00	3,825,399	85
86	2015	0	1	1.00	0	86
87	2016	0	1	1.00	0	87
88	2017	0	1	1.00	0	88
89	2018	0	1	1.00	0	89
90	2019	0	1	1.00	0	90
91	Total	$ 4,216,706			$ 4,216,706	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

	Account 390.1 - General Plant Structures					
Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	19	25.68	$ 0	1
2	1931	0	17	28.71	0	2
3	1932	0	16	30.50	0	3
4	1933	0	17	28.71	0	4
5	1934	0	19	25.68	0	5
6	1935	0	18	27.11	0	6
7	1936	0	19	25.68	0	7
8	1937	0	20	24.40	0	8
9	1938	0	20	24.40	0	9
10	1939	0	20	24.40	0	10
11	1940	0	20	24.40	0	11
12	1941	0	22	22.18	0	12
13	1942	0	23	21.22	0	13
14	1943	0	23	21.22	0	14
15	1944	0	24	20.33	0	15
16	1945	0	24	20.33	0	16
17	1946	0	27	18.07	0	17
18	1947	0	32	15.25	0	18
19	1948	0	36	13.56	0	19
20	1949	0	37	13.19	0	20
21	1950	0	39	12.51	0	21
22	1951	0	42	11.62	0	22
23	1952	0	44	11.09	0	23
24	1953	0	44	11.09	0	24
25	1954	0	46	10.61	0	25
26	1955	0	48	10.17	0	26
27	1956	0	52	9.38	0	27
28	1957	0	55	8.87	0	28
29	1958	0	57	8.56	0	29
30	1959	0	58	8.41	0	30
31	1960	0	59	8.27	0	31
32	1961	0	58	8.41	0	32
33	1962	0	59	8.27	0	33
34	1963	0	60	8.13	0	34
35	1964	0	61	8.00	0	35
36	1965	0	64	7.63	0	36
37	1966	0	65	7.51	0	37
38	1967	0	67	7.28	0	38
39	1968	0	71	6.87	0	39
40	1969	0	75	6.51	0	40
41	1970	0	79	6.18	0	41
42	1971	0	87	5.61	0	42
43	1972	0	93	5.25	0	43
44	1973	0	100	4.88	0	44
45	1974	0	118	4.14	0	45
46	1975	0	133	3.67	0	46
47	1976	0	138	3.54	0	47
48	1977	0	148	3.30	0	48
49	1978	0	161	3.03	0	49
50	1979	0	177	2.76	0	50
51	1980	0	194	2.52	0	51
52	1981	0	204	2.39	0	52
53	1982	0	207	2.36	0	53
54	1983	0	215	2.27	0	54
55	1984	0	224	2.18	0	55
56	1985	0	226	2.16	0	56
57	1986	0	231	2.11	0	57
58	1987	477,495	232	2.10	1,002,740	58
59	1988	0	233	2.09	0	59
60	1989	9,855,902	232	2.10	20,697,394	60
61	1990	0	237	2.06	0	61
62	1991	0	233	2.09	0	62
63	1992	0	238	2.05	0	63
64	1993	21,094	250	1.95	41,133	64
65	1994	0	261	1.87	0	65
66	1995	0	265	1.84	0	66
67	1996	0	176	2.77	0	67
68	1997	50,000	282	1.73	86,500	68
69	1998	4,191	285	1.71	7,167	69
70	1999	40,000	287	1.70	68,000	70
71	2000	0	295	1.65	0	71
72	2001	24,594	303	1.61	39,596	72
73	2002	0	310	1.57	0	73
74	2003	119,057	320	1.53	182,157	74
75	2004	265,902	342	1.43	380,240	75
76	2005	2,018,722	355	1.37	2,765,649	76
77	2006	143,605	364	1.34	192,431	77
78	2007	356,318	382	1.28	456,087	78
79	2008	435,364	398	1.23	535,498	79
80	2009	241,073	389	1.25	301,341	80
81	2010	546,888	399	1.22	667,203	81
82	2011	0	411	1.19	0	82
83	2012	476,843	422	1.16	553,138	83
84	2013	188,416	431	1.13	212,910	84
85	2014	13,225,201	440	1.11	14,679,973	85
86	2015	798,504	442	1.10	878,354	86
87	2016	1,437,730	447	1.09	1,567,126	87
88	2017	4,138,147	465	1.05	4,345,054	88
89	2018	147,495	481	1.01	148,970	89
90	2019	0	488	1.00	0	90
91	Total	$ 35,012,541			$ 49,808,661	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 390.2 - Leasehold Improvements

Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	19	25.68	$ 0	1
2	1931	0	17	28.71	0	2
3	1932	0	16	30.50	0	3
4	1933	0	17	28.71	0	4
5	1934	0	19	25.68	0	5
6	1935	0	18	27.11	0	6
7	1936	0	19	25.68	0	7
8	1937	0	20	24.40	0	8
9	1938	0	20	24.40	0	9
10	1939	0	20	24.40	0	10
11	1940	0	20	24.40	0	11
12	1941	0	22	22.18	0	12
13	1942	0	23	21.22	0	13
14	1943	0	23	21.22	0	14
15	1944	0	24	20.33	0	15
16	1945	0	24	20.33	0	16
17	1946	0	27	18.07	0	17
18	1947	0	32	15.25	0	18
19	1948	0	36	13.56	0	19
20	1949	0	37	13.19	0	20
21	1950	0	39	12.51	0	21
22	1951	0	42	11.62	0	22
23	1952	0	44	11.09	0	23
24	1953	0	44	11.09	0	24
25	1954	0	46	10.61	0	25
26	1955	0	48	10.17	0	26
27	1956	0	52	9.38	0	27
28	1957	0	55	8.87	0	28
29	1958	0	57	8.56	0	29
30	1959	0	58	8.41	0	30
31	1960	0	59	8.27	0	31
32	1961	0	58	8.41	0	32
33	1962	0	59	8.27	0	33
34	1963	0	60	8.13	0	34
35	1964	0	61	8.00	0	35
36	1965	0	64	7.63	0	36
37	1966	0	65	7.51	0	37
38	1967	0	67	7.28	0	38
39	1968	0	71	6.87	0	39
40	1969	0	75	6.51	0	40
41	1970	0	79	6.18	0	41
42	1971	0	87	5.61	0	42
43	1972	0	93	5.25	0	43
44	1973	0	100	4.88	0	44
45	1974	0	118	4.14	0	45
46	1975	0	133	3.67	0	46
47	1976	0	138	3.54	0	47
48	1977	0	148	3.30	0	48
49	1978	0	161	3.03	0	49
50	1979	0	177	2.76	0	50
51	1980	0	194	2.52	0	51
52	1981	0	204	2.39	0	52
53	1982	0	207	2.36	0	53
54	1983	47,186	215	2.27	107,112	54
55	1984	3,685	224	2.18	8,033	55
56	1985	2,427	226	2.16	5,242	56
57	1986	1,880	231	2.11	3,967	57
58	1987	4,071	232	2.10	8,549	58
59	1988	0	233	2.09	0	59
60	1989	0	232	2.10	0	60
61	1990	0	237	2.06	0	61
62	1991	0	233	2.09	0	62
63	1992	0	238	2.05	0	63
64	1993	192,953	250	1.95	376,258	64
65	1994	0	261	1.87	0	65
66	1995	0	265	1.84	0	66
67	1996	0	176	2.77	0	67
68	1997	0	282	1.73	0	68
69	1998	0	285	1.71	0	69
70	1999	0	287	1.70	0	70
71	2000	20,560	295	1.65	33,924	71
72	2001	0	303	1.61	0	72
73	2002	0	310	1.57	0	73
74	2003	59,871	320	1.53	91,603	74
75	2004	60,915	342	1.43	87,108	75
76	2005	0	355	1.37	0	76
77	2006	0	364	1.34	0	77
78	2007	153,898	382	1.28	196,989	78
79	2008	6,504	398	1.23	8,000	79
80	2009	675	389	1.25	844	80
81	2010	0	399	1.22	0	81
82	2011	0	411	1.19	0	82
83	2012	296,119	422	1.16	343,498	83
84	2013	299,336	431	1.13	338,250	84
85	2014	665,766	440	1.11	739,000	85
86	2015	0	442	1.10	0	86
87	2016	185,781	447	1.09	202,501	87
88	2017	503,195	465	1.05	528,355	88
89	2018	0	481	1.01	0	89
90	2019	0	488	1.00	0	90
91	Total	$ 2,504,822			$ 3,079,233	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 391 - Office Furniture and Equipment

Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	11	42.55	$ 0	1
2	1931	0	11	42.55	0	2
3	1932	0	11	42.55	0	3
4	1933	0	11	42.55	0	4
5	1934	0	11	42.55	0	5
6	1935	0	11	42.55	0	6
7	1936	0	12	39.00	0	7
8	1937	0	13	36.00	0	8
9	1938	0	13	36.00	0	9
10	1939	0	13	36.00	0	10
11	1940	0	13	36.00	0	11
12	1941	0	13	36.00	0	12
13	1942	0	15	31.20	0	13
14	1943	0	15	31.20	0	14
15	1944	0	15	31.20	0	15
16	1945	0	16	29.25	0	16
17	1946	0	20	23.40	0	17
18	1947	0	23	20.35	0	18
19	1948	0	26	18.00	0	19
20	1949	0	26	18.00	0	20
21	1950	0	27	17.33	0	21
22	1951	0	29	16.14	0	22
23	1952	0	31	15.10	0	23
24	1953	0	33	14.18	0	24
25	1954	0	34	13.76	0	25
26	1955	0	36	13.00	0	26
27	1956	0	39	12.00	0	27
28	1957	0	41	11.41	0	28
29	1958	0	42	11.14	0	29
30	1959	0	45	10.40	0	30
31	1960	0	46	10.17	0	31
32	1961	0	51	9.18	0	32
33	1962	0	53	8.83	0	33
34	1963	0	55	8.51	0	34
35	1964	0	57	8.21	0	35
36	1965	0	60	7.80	0	36
37	1966	0	62	7.55	0	37
38	1967	0	66	7.09	0	38
39	1968	0	70	6.69	0	39
40	1969	0	74	6.32	0	40
41	1970	0	81	5.78	0	41
42	1971	0	87	5.38	0	42
43	1972	0	94	4.98	0	43
44	1973	0	100	4.68	0	44
45	1974	0	109	4.29	0	45
46	1975	0	123	3.80	0	46
47	1976	0	130	3.60	0	47
48	1977	0	141	3.32	0	48
49	1978	0	151	3.10	0	49
50	1979	0	164	2.85	0	50
51	1980	0	178	2.63	0	51
52	1981	0	186	2.52	0	52
53	1982	0	203	2.31	0	53
54	1983	0	209	2.24	0	54
55	1984	0	212	2.21	0	55
56	1985	0	211	2.22	0	56
57	1986	0	218	2.15	0	57
58	1987	0	226	2.07	0	58
59	1988	0	219	2.14	0	59
60	1989	0	213	2.20	0	60
61	1990	0	228	2.05	0	61
62	1991	0	242	1.93	0	62
63	1992	0	249	1.88	0	63
64	1993	0	260	1.80	0	64
65	1994	0	257	1.82	0	65
66	1995	0	246	1.90	0	66
67	1996	0	250	1.87	0	67
68	1997	0	251	1.86	0	68
69	1998	0	254	1.84	0	69
70	1999	0	261	1.79	0	70
71	2000	0	268	1.75	0	71
72	2001	0	280	1.67	0	72
73	2002	0	289	1.62	0	73
74	2003	0	293	1.60	0	74
75	2004	218,068	298	1.57	342,367	75
76	2005	146,299	303	1.54	225,300	76
77	2006	1,382,849	305	1.53	2,115,759	77
78	2007	2,831,972	317	1.48	4,191,319	78
79	2008	125,388	337	1.39	174,289	79
80	2009	313,150	359	1.30	407,095	80
81	2010	222,355	375	1.25	277,944	81
82	2011	416,815	387	1.21	504,346	82
83	2012	281,912	405	1.16	327,018	83
84	2013	675,580	412	1.14	770,161	84
85	2014	364,405	427	1.10	400,846	85
86	2015	503,359	429	1.09	548,661	86
87	2016	653,396	440	1.06	692,600	87
88	2017	81,451	449	1.04	84,709	88
89	2018	136,664	468	1.00	136,664	89
90	2019	0	468	1.00	0	90
91	Total	$ 8,353,663			$ 11,199,078	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 391.1 - Computer Equipment

Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	11	42.55	$ 0	1
2	1931	0	11	42.55	0	2
3	1932	0	11	42.55	0	3
4	1933	0	11	42.55	0	4
5	1934	0	11	42.55	0	5
6	1935	0	11	42.55	0	6
7	1936	0	12	39.00	0	7
8	1937	0	13	36.00	0	8
9	1938	0	13	36.00	0	9
10	1939	0	13	36.00	0	10
11	1940	0	13	36.00	0	11
12	1941	0	13	36.00	0	12
13	1942	0	15	31.20	0	13
14	1943	0	15	31.20	0	14
15	1944	0	15	31.20	0	15
16	1945	0	16	29.25	0	16
17	1946	0	20	23.40	0	17
18	1947	0	23	20.35	0	18
19	1948	0	26	18.00	0	19
20	1949	0	26	18.00	0	20
21	1950	0	27	17.33	0	21
22	1951	0	29	16.14	0	22
23	1952	0	31	15.10	0	23
24	1953	0	33	14.18	0	24
25	1954	0	34	13.76	0	25
26	1955	0	36	13.00	0	26
27	1956	0	39	12.00	0	27
28	1957	0	41	11.41	0	28
29	1958	0	42	11.14	0	29
30	1959	0	45	10.40	0	30
31	1960	0	46	10.17	0	31
32	1961	0	51	9.18	0	32
33	1962	0	53	8.83	0	33
34	1963	0	55	8.51	0	34
35	1964	0	57	8.21	0	35
36	1965	0	60	7.80	0	36
37	1966	0	62	7.55	0	37
38	1967	0	66	7.09	0	38
39	1968	0	70	6.69	0	39
40	1969	0	74	6.32	0	40
41	1970	0	81	5.78	0	41
42	1971	0	87	5.38	0	42
43	1972	0	94	4.98	0	43
44	1973	0	100	4.68	0	44
45	1974	0	109	4.29	0	45
46	1975	0	123	3.80	0	46
47	1976	0	130	3.60	0	47
48	1977	0	141	3.32	0	48
49	1978	0	151	3.10	0	49
50	1979	0	164	2.85	0	50
51	1980	0	178	2.63	0	51
52	1981	0	186	2.52	0	52
53	1982	0	203	2.31	0	53
54	1983	0	209	2.24	0	54
55	1984	0	212	2.21	0	55
56	1985	0	211	2.22	0	56
57	1986	0	218	2.15	0	57
58	1987	0	226	2.07	0	58
59	1988	0	219	2.14	0	59
60	1989	0	213	2.20	0	60
61	1990	0	228	2.05	0	61
62	1991	0	242	1.93	0	62
63	1992	0	249	1.88	0	63
64	1993	0	260	1.80	0	64
65	1994	0	257	1.82	0	65
66	1995	0	246	1.90	0	66
67	1996	0	250	1.87	0	67
68	1997	0	251	1.86	0	68
69	1998	0	254	1.84	0	69
70	1999	0	261	1.79	0	70
71	2000	0	268	1.75	0	71
72	2001	0	280	1.67	0	72
73	2002	0	289	1.62	0	73
74	2003	0	293	1.60	0	74
75	2004	0	298	1.57	0	75
76	2005	0	303	1.54	0	76
77	2006	0	305	1.53	0	77
78	2007	0	317	1.48	0	78
79	2008	0	337	1.39	0	79
80	2009	0	359	1.30	0	80
81	2010	0	375	1.25	0	81
82	2011	0	387	1.21	0	82
83	2012	0	405	1.16	0	83
84	2013	0	412	1.14	0	84
85	2014	1,850,410	427	1.10	2,035,451	85
86	2015	1,520,345	429	1.09	1,657,176	86
87	2016	4,387,450	440	1.06	4,650,697	87
88	2017	5,726,511	449	1.04	5,955,571	88
89	2018	1,942,059	468	1.00	1,942,059	89
90	2019	549,456	468	1.00	549,456	90
91	Total	$ 15,976,231			$ 16,790,410	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 392.11 - Transportation Equip. - Light Vehicles

Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	22	23.55	$ 0	1
2	1931	0	20	25.90	0	2
3	1932	0	19	27.26	0	3
4	1933	0	19	27.26	0	4
5	1934	0	20	25.90	0	5
6	1935	0	21	24.67	0	6
7	1936	0	21	24.67	0	7
8	1937	0	23	22.52	0	8
9	1938	0	23	22.52	0	9
10	1939	0	23	22.52	0	10
11	1940	0	24	21.58	0	11
12	1941	0	25	20.72	0	12
13	1942	0	28	18.50	0	13
14	1943	0	29	17.86	0	14
15	1944	0	29	17.86	0	15
16	1945	0	29	17.86	0	16
17	1946	0	34	15.24	0	17
18	1947	0	37	14.00	0	18
19	1948	0	39	13.28	0	19
20	1949	0	40	12.95	0	20
21	1950	0	42	12.33	0	21
22	1951	0	45	11.51	0	22
23	1952	0	46	11.26	0	23
24	1953	0	49	10.57	0	24
25	1954	0	49	10.57	0	25
26	1955	0	51	10.16	0	26
27	1956	0	55	9.42	0	27
28	1957	0	59	8.78	0	28
29	1958	0	62	8.35	0	29
30	1959	0	64	8.09	0	30
31	1960	0	65	7.97	0	31
32	1961	0	67	7.73	0	32
33	1962	0	67	7.73	0	33
34	1963	0	68	7.62	0	34
35	1964	0	70	7.40	0	35
36	1965	0	71	7.30	0	36
37	1966	0	73	7.10	0	37
38	1967	0	76	6.82	0	38
39	1968	0	80	6.48	0	39
40	1969	0	84	6.17	0	40
41	1970	0	88	5.89	0	41
42	1971	0	93	5.57	0	42
43	1972	0	95	5.45	0	43
44	1973	0	100	5.18	0	44
45	1974	0	117	4.43	0	45
46	1975	0	141	3.67	0	46
47	1976	0	153	3.39	0	47
48	1977	0	164	3.16	0	48
49	1978	0	178	2.91	0	49
50	1979	0	197	2.63	0	50
51	1980	0	222	2.33	0	51
52	1981	0	246	2.11	0	52
53	1982	0	263	1.97	0	53
54	1983	0	269	1.93	0	54
55	1984	0	273	1.90	0	55
56	1985	0	276	1.88	0	56
57	1986	0	280	1.85	0	57
58	1987	0	286	1.81	0	58
59	1988	0	295	1.76	0	59
60	1989	0	281	1.84	0	60
61	1990	0	298	1.74	0	61
62	1991	0	320	1.62	0	62
63	1992	0	316	1.64	0	63
64	1993	0	324	1.60	0	64
65	1994	0	331	1.56	0	65
66	1995	0	333	1.56	0	66
67	1996	0	336	1.54	0	67
68	1997	0	351	1.48	0	68
69	1998	0	380	1.36	0	69
70	1999	0	385	1.35	0	70
71	2000	0	389	1.33	0	71
72	2001	0	390	1.33	0	72
73	2002	0	395	1.31	0	73
74	2003	0	401	1.29	0	74
75	2004	0	414	1.25	0	75
76	2005	0	439	1.18	0	76
77	2006	0	457	1.13	0	77
78	2007	0	469	1.10	0	78
79	2008	0	485	1.07	0	79
80	2009	0	501	1.03	0	80
81	2010	0	503	1.03	0	81
82	2011	504,948	516	1.00	504,948	82
83	2012	271,760	538	0.96	260,890	83
84	2013	71,888	551	0.94	67,575	84
85	2014	1,022,743	560	0.93	951,151	85
86	2015	337,929	567	0.91	307,515	86
87	2016	278,379	573	0.90	250,541	87
88	2017	603,917	578	0.90	543,525	88
89	2018	206,876	576	0.90	186,188	89
90	2019	62,838	518	1.00	62,838	90
91	Total	$ 3,361,278			$ 3,135,171	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

	Account 392.21 - Transportation Equip - Aircraft					
Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	22	23.55	$ 0	1
2	1931	0	20	25.90	0	2
3	1932	0	19	27.26	0	3
4	1933	0	19	27.26	0	4
5	1934	0	20	25.90	0	5
6	1935	0	21	24.67	0	6
7	1936	0	21	24.67	0	7
8	1937	0	23	22.52	0	8
9	1938	0	23	22.52	0	9
10	1939	0	23	22.52	0	10
11	1940	0	24	21.58	0	11
12	1941	0	25	20.72	0	12
13	1942	0	28	18.50	0	13
14	1943	0	29	17.86	0	14
15	1944	0	29	17.86	0	15
16	1945	0	29	17.86	0	16
17	1946	0	34	15.24	0	17
18	1947	0	37	14.00	0	18
19	1948	0	39	13.28	0	19
20	1949	0	40	12.95	0	20
21	1950	0	42	12.33	0	21
22	1951	0	45	11.51	0	22
23	1952	0	46	11.26	0	23
24	1953	0	49	10.57	0	24
25	1954	0	49	10.57	0	25
26	1955	0	51	10.16	0	26
27	1956	0	55	9.42	0	27
28	1957	0	59	8.78	0	28
29	1958	0	62	8.35	0	29
30	1959	0	64	8.09	0	30
31	1960	0	65	7.97	0	31
32	1961	0	67	7.73	0	32
33	1962	0	67	7.73	0	33
34	1963	0	68	7.62	0	34
35	1964	0	70	7.40	0	35
36	1965	0	71	7.30	0	36
37	1966	0	73	7.10	0	37
38	1967	0	76	6.82	0	38
39	1968	0	80	6.48	0	39
40	1969	0	84	6.17	0	40
41	1970	0	88	5.89	0	41
42	1971	0	93	5.57	0	42
43	1972	0	95	5.45	0	43
44	1973	0	100	5.18	0	44
45	1974	0	117	4.43	0	45
46	1975	0	141	3.67	0	46
47	1976	0	153	3.39	0	47
48	1977	0	164	3.16	0	48
49	1978	0	178	2.91	0	49
50	1979	0	197	2.63	0	50
51	1980	0	222	2.33	0	51
52	1981	0	246	2.11	0	52
53	1982	0	263	1.97	0	53
54	1983	0	269	1.93	0	54
55	1984	0	273	1.90	0	55
56	1985	0	276	1.88	0	56
57	1986	0	280	1.85	0	57
58	1987	0	286	1.81	0	58
59	1988	0	295	1.76	0	59
60	1989	0	281	1.84	0	60
61	1990	0	298	1.74	0	61
62	1991	0	320	1.62	0	62
63	1992	0	316	1.64	0	63
64	1993	0	324	1.60	0	64
65	1994	0	331	1.56	0	65
66	1995	0	333	1.56	0	66
67	1996	0	336	1.54	0	67
68	1997	0	351	1.48	0	68
69	1998	0	380	1.36	0	69
70	1999	0	385	1.35	0	70
71	2000	0	389	1.33	0	71
72	2001	0	390	1.33	0	72
73	2002	0	395	1.31	0	73
74	2003	0	401	1.29	0	74
75	2004	0	414	1.25	0	75
76	2005	0	439	1.18	0	76
77	2006	0	457	1.13	0	77
78	2007	0	469	1.10	0	78
79	2008	0	485	1.07	0	79
80	2009	0	501	1.03	0	80
81	2010	0	503	1.03	0	81
82	2011	8,221,361	516	1.00	8,221,361	82
83	2012	0	538	0.96	0	83
84	2013	0	551	0.94	0	84
85	2014	0	560	0.93	0	85
86	2015	0	567	0.91	0	86
87	2016	0	573	0.90	0	87
88	2017	0	578	0.90	0	88
89	2018	0	576	0.90	0	89
90	2019	0	518	1.00	0	90
91	Total	$ 8,221,361			$ 8,221,361	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 393 - Stores Equipment

Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	22	23.55	$ 0	1
2	1931	0	20	25.90	0	2
3	1932	0	19	27.26	0	3
4	1933	0	19	27.26	0	4
5	1934	0	20	25.90	0	5
6	1935	0	21	24.67	0	6
7	1936	0	21	24.67	0	7
8	1937	0	23	22.52	0	8
9	1938	0	23	22.52	0	9
10	1939	0	23	22.52	0	10
11	1940	0	24	21.58	0	11
12	1941	0	25	20.72	0	12
13	1942	0	28	18.50	0	13
14	1943	0	29	17.86	0	14
15	1944	0	29	17.86	0	15
16	1945	0	29	17.86	0	16
17	1946	0	34	15.24	0	17
18	1947	0	37	14.00	0	18
19	1948	0	39	13.28	0	19
20	1949	0	40	12.95	0	20
21	1950	0	42	12.33	0	21
22	1951	0	45	11.51	0	22
23	1952	0	46	11.26	0	23
24	1953	0	49	10.57	0	24
25	1954	0	49	10.57	0	25
26	1955	0	51	10.16	0	26
27	1956	0	55	9.42	0	27
28	1957	0	59	8.78	0	28
29	1958	0	62	8.35	0	29
30	1959	0	64	8.09	0	30
31	1960	0	65	7.97	0	31
32	1961	0	67	7.73	0	32
33	1962	0	67	7.73	0	33
34	1963	0	68	7.62	0	34
35	1964	0	70	7.40	0	35
36	1965	0	71	7.30	0	36
37	1966	0	73	7.10	0	37
38	1967	0	76	6.82	0	38
39	1968	0	80	6.48	0	39
40	1969	0	84	6.17	0	40
41	1970	0	88	5.89	0	41
42	1971	0	93	5.57	0	42
43	1972	0	95	5.45	0	43
44	1973	0	100	5.18	0	44
45	1974	0	117	4.43	0	45
46	1975	0	141	3.67	0	46
47	1976	0	153	3.39	0	47
48	1977	0	164	3.16	0	48
49	1978	0	178	2.91	0	49
50	1979	0	197	2.63	0	50
51	1980	0	222	2.33	0	51
52	1981	0	246	2.11	0	52
53	1982	0	263	1.97	0	53
54	1983	0	269	1.93	0	54
55	1984	0	273	1.90	0	55
56	1985	0	276	1.88	0	56
57	1986	0	280	1.85	0	57
58	1987	0	286	1.81	0	58
59	1988	0	295	1.76	0	59
60	1989	0	281	1.84	0	60
61	1990	0	298	1.74	0	61
62	1991	0	320	1.62	0	62
63	1992	0	316	1.64	0	63
64	1993	0	324	1.60	0	64
65	1994	0	331	1.56	0	65
66	1995	0	333	1.56	0	66
67	1996	0	336	1.54	0	67
68	1997	0	351	1.48	0	68
69	1998	0	380	1.36	0	69
70	1999	0	385	1.35	0	70
71	2000	0	389	1.33	0	71
72	2001	0	390	1.33	0	72
73	2002	0	395	1.31	0	73
74	2003	0	401	1.29	0	74
75	2004	0	414	1.25	0	75
76	2005	0	439	1.18	0	76
77	2006	0	457	1.13	0	77
78	2007	0	469	1.10	0	78
79	2008	31,617	485	1.07	33,830	79
80	2009	0	501	1.03	0	80
81	2010	0	503	1.03	0	81
82	2011	0	516	1.00	0	82
83	2012	0	538	0.96	0	83
84	2013	0	551	0.94	0	84
85	2014	0	560	0.93	0	85
86	2015	0	567	0.91	0	86
87	2016	31,420	573	0.90	28,278	87
88	2017	0	578	0.90	0	88
89	2018	0	576	0.90	0	89
90	2019	0	518	1.00	0	90
91	Total	$ 63,037			$ 62,108	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

	Account 394 - Tools, Shop, and Garage Equipment					
Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	22	23.55	$ 0	1
2	1931	0	20	25.90	0	2
3	1932	0	19	27.26	0	3
4	1933	0	19	27.26	0	4
5	1934	0	20	25.90	0	5
6	1935	0	21	24.67	0	6
7	1936	0	21	24.67	0	7
8	1937	0	23	22.52	0	8
9	1938	0	23	22.52	0	9
10	1939	0	23	22.52	0	10
11	1940	0	24	21.58	0	11
12	1941	0	25	20.72	0	12
13	1942	0	28	18.50	0	13
14	1943	0	29	17.86	0	14
15	1944	0	29	17.86	0	15
16	1945	0	29	17.86	0	16
17	1946	0	34	15.24	0	17
18	1947	0	37	14.00	0	18
19	1948	0	39	13.28	0	19
20	1949	0	40	12.95	0	20
21	1950	0	42	12.33	0	21
22	1951	0	45	11.51	0	22
23	1952	0	46	11.26	0	23
24	1953	0	49	10.57	0	24
25	1954	0	49	10.57	0	25
26	1955	0	51	10.16	0	26
27	1956	0	55	9.42	0	27
28	1957	0	59	8.78	0	28
29	1958	0	62	8.35	0	29
30	1959	0	64	8.09	0	30
31	1960	0	65	7.97	0	31
32	1961	0	67	7.73	0	32
33	1962	0	67	7.73	0	33
34	1963	0	68	7.62	0	34
35	1964	0	70	7.40	0	35
36	1965	0	71	7.30	0	36
37	1966	0	73	7.10	0	37
38	1967	0	76	6.82	0	38
39	1968	0	80	6.48	0	39
40	1969	0	84	6.17	0	40
41	1970	0	88	5.89	0	41
42	1971	0	93	5.57	0	42
43	1972	0	95	5.45	0	43
44	1973	0	100	5.18	0	44
45	1974	0	117	4.43	0	45
46	1975	0	141	3.67	0	46
47	1976	0	153	3.39	0	47
48	1977	0	164	3.16	0	48
49	1978	0	178	2.91	0	49
50	1979	0	197	2.63	0	50
51	1980	0	222	2.33	0	51
52	1981	0	246	2.11	0	52
53	1982	0	263	1.97	0	53
54	1983	0	269	1.93	0	54
55	1984	0	273	1.90	0	55
56	1985	0	276	1.88	0	56
57	1986	0	280	1.85	0	57
58	1987	0	286	1.81	0	58
59	1988	0	295	1.76	0	59
60	1989	0	281	1.84	0	60
61	1990	0	298	1.74	0	61
62	1991	0	320	1.62	0	62
63	1992	0	316	1.64	0	63
64	1993	0	324	1.60	0	64
65	1994	0	331	1.56	0	65
66	1995	0	333	1.56	0	66
67	1996	0	336	1.54	0	67
68	1997	0	351	1.48	0	68
69	1998	0	380	1.36	0	69
70	1999	0	385	1.35	0	70
71	2000	0	389	1.33	0	71
72	2001	0	390	1.33	0	72
73	2002	0	395	1.31	0	73
74	2003	0	401	1.29	0	74
75	2004	9,686	414	1.25	12,108	75
76	2005	26,730	439	1.18	31,541	76
77	2006	5,013	457	1.13	5,665	77
78	2007	80,661	469	1.10	88,727	78
79	2008	0	485	1.07	0	79
80	2009	17,816	501	1.03	18,350	80
81	2010	44,295	503	1.03	45,624	81
82	2011	149,171	516	1.00	149,171	82
83	2012	115,235	538	0.96	110,626	83
84	2013	87,743	551	0.94	82,478	84
85	2014	60,701	560	0.93	56,452	85
86	2015	45,484	567	0.91	41,390	86
87	2016	19,608	573	0.90	17,647	87
88	2017	324,144	578	0.90	291,730	88
89	2018	120,024	576	0.90	108,022	89
90	2019	0	518	1.00	0	90
91	Total	$ 1,106,311			$ 1,059,531	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

	Account 395 - Laboratory Equipment					
Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	11	42.55	$ 0	1
2	1931	0	11	42.55	0	2
3	1932	0	11	42.55	0	3
4	1933	0	11	42.55	0	4
5	1934	0	11	42.55	0	5
6	1935	0	11	42.55	0	6
7	1936	0	12	39.00	0	7
8	1937	0	13	36.00	0	8
9	1938	0	13	36.00	0	9
10	1939	0	13	36.00	0	10
11	1940	0	13	36.00	0	11
12	1941	0	13	36.00	0	12
13	1942	0	15	31.20	0	13
14	1943	0	15	31.20	0	14
15	1944	0	15	31.20	0	15
16	1945	0	16	29.25	0	16
17	1946	0	20	23.40	0	17
18	1947	0	23	20.35	0	18
19	1948	0	26	18.00	0	19
20	1949	0	26	18.00	0	20
21	1950	0	27	17.33	0	21
22	1951	0	29	16.14	0	22
23	1952	0	31	15.10	0	23
24	1953	0	33	14.18	0	24
25	1954	0	34	13.76	0	25
26	1955	0	36	13.00	0	26
27	1956	0	39	12.00	0	27
28	1957	0	41	11.41	0	28
29	1958	0	42	11.14	0	29
30	1959	0	45	10.40	0	30
31	1960	0	46	10.17	0	31
32	1961	0	51	9.18	0	32
33	1962	0	53	8.83	0	33
34	1963	0	55	8.51	0	34
35	1964	0	57	8.21	0	35
36	1965	0	60	7.80	0	36
37	1966	0	62	7.55	0	37
38	1967	0	66	7.09	0	38
39	1968	0	70	6.69	0	39
40	1969	0	74	6.32	0	40
41	1970	0	81	5.78	0	41
42	1971	0	87	5.38	0	42
43	1972	0	94	4.98	0	43
44	1973	0	100	4.68	0	44
45	1974	0	109	4.29	0	45
46	1975	0	123	3.80	0	46
47	1976	0	130	3.60	0	47
48	1977	0	141	3.32	0	48
49	1978	0	151	3.10	0	49
50	1979	0	164	2.85	0	50
51	1980	0	178	2.63	0	51
52	1981	0	186	2.52	0	52
53	1982	0	203	2.31	0	53
54	1983	0	209	2.24	0	54
55	1984	0	212	2.21	0	55
56	1985	0	211	2.22	0	56
57	1986	0	218	2.15	0	57
58	1987	0	226	2.07	0	58
59	1988	0	219	2.14	0	59
60	1989	0	213	2.20	0	60
61	1990	0	228	2.05	0	61
62	1991	0	242	1.93	0	62
63	1992	0	249	1.88	0	63
64	1993	0	260	1.80	0	64
65	1994	0	257	1.82	0	65
66	1995	0	246	1.90	0	66
67	1996	0	250	1.87	0	67
68	1997	0	251	1.86	0	68
69	1998	0	254	1.84	0	69
70	1999	0	261	1.79	0	70
71	2000	0	268	1.75	0	71
72	2001	0	280	1.67	0	72
73	2002	46,970	289	1.62	76,091	73
74	2003	0	293	1.60	0	74
75	2004	15,738	298	1.57	24,709	75
76	2005	44,639	303	1.54	68,744	76
77	2006	0	305	1.53	0	77
78	2007	41,607	317	1.48	61,578	78
79	2008	15,774	337	1.39	21,926	79
80	2009	173,206	359	1.30	225,168	80
81	2010	0	375	1.25	0	81
82	2011	48,182	387	1.21	58,300	82
83	2012	4,376	405	1.16	5,076	83
84	2013	296,878	412	1.14	338,441	84
85	2014	224,898	427	1.10	247,388	85
86	2015	54,031	429	1.09	58,894	86
87	2016	13,913	440	1.06	14,748	87
88	2017	132,717	449	1.04	138,026	88
89	2018	0	468	1.00	0	89
90	2019	0	468	1.00	0	90
91	Total	$ 1,112,929			$ 1,339,089	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

	Account 396 - Power Operated Equipment					
Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	22	23.55	$ 0	1
2	1931	0	20	25.90	0	2
3	1932	0	19	27.26	0	3
4	1933	0	19	27.26	0	4
5	1934	0	20	25.90	0	5
6	1935	0	21	24.67	0	6
7	1936	0	21	24.67	0	7
8	1937	0	23	22.52	0	8
9	1938	0	23	22.52	0	9
10	1939	0	23	22.52	0	10
11	1940	0	24	21.58	0	11
12	1941	0	25	20.72	0	12
13	1942	0	28	18.50	0	13
14	1943	0	29	17.86	0	14
15	1944	0	29	17.86	0	15
16	1945	0	29	17.86	0	16
17	1946	0	34	15.24	0	17
18	1947	0	37	14.00	0	18
19	1948	0	39	13.28	0	19
20	1949	0	40	12.95	0	20
21	1950	0	42	12.33	0	21
22	1951	0	45	11.51	0	22
23	1952	0	46	11.26	0	23
24	1953	0	49	10.57	0	24
25	1954	0	49	10.57	0	25
26	1955	0	51	10.16	0	26
27	1956	0	55	9.42	0	27
28	1957	0	59	8.78	0	28
29	1958	0	62	8.35	0	29
30	1959	0	64	8.09	0	30
31	1960	0	65	7.97	0	31
32	1961	0	67	7.73	0	32
33	1962	0	67	7.73	0	33
34	1963	0	68	7.62	0	34
35	1964	0	70	7.40	0	35
36	1965	0	71	7.30	0	36
37	1966	0	73	7.10	0	37
38	1967	0	76	6.82	0	38
39	1968	0	80	6.48	0	39
40	1969	0	84	6.17	0	40
41	1970	0	88	5.89	0	41
42	1971	0	93	5.57	0	42
43	1972	0	95	5.45	0	43
44	1973	0	100	5.18	0	44
45	1974	0	117	4.43	0	45
46	1975	0	141	3.67	0	46
47	1976	0	153	3.39	0	47
48	1977	0	164	3.16	0	48
49	1978	0	178	2.91	0	49
50	1979	0	197	2.63	0	50
51	1980	0	222	2.33	0	51
52	1981	0	246	2.11	0	52
53	1982	0	263	1.97	0	53
54	1983	0	269	1.93	0	54
55	1984	0	273	1.90	0	55
56	1985	0	276	1.88	0	56
57	1986	0	280	1.85	0	57
58	1987	0	286	1.81	0	58
59	1988	0	295	1.76	0	59
60	1989	0	281	1.84	0	60
61	1990	0	298	1.74	0	61
62	1991	0	320	1.62	0	62
63	1992	0	316	1.64	0	63
64	1993	0	324	1.60	0	64
65	1994	0	331	1.56	0	65
66	1995	0	333	1.56	0	66
67	1996	0	336	1.54	0	67
68	1997	0	351	1.48	0	68
69	1998	0	380	1.36	0	69
70	1999	0	385	1.35	0	70
71	2000	0	389	1.33	0	71
72	2001	0	390	1.33	0	72
73	2002	0	395	1.31	0	73
74	2003	0	401	1.29	0	74
75	2004	0	414	1.25	0	75
76	2005	0	439	1.18	0	76
77	2006	0	457	1.13	0	77
78	2007	0	469	1.10	0	78
79	2008	0	485	1.07	0	79
80	2009	11,760	501	1.03	12,113	80
81	2010	0	503	1.03	0	81
82	2011	0	516	1.00	0	82
83	2012	0	538	0.96	0	83
84	2013	0	551	0.94	0	84
85	2014	0	560	0.93	0	85
86	2015	0	567	0.91	0	86
87	2016	0	573	0.90	0	87
88	2017	0	578	0.90	0	88
89	2018	0	576	0.90	0	89
90	2019	0	518	1.00	0	90
91	Total	$ 11,760			$ 12,113	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 397 - Communication Equipment

Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	15	32.07	$ 0	1
2	1931	0	15	32.07	0	2
3	1932	0	15	32.07	0	3
4	1933	0	15	32.07	0	4
5	1934	0	15	32.07	0	5
6	1935	0	15	32.07	0	6
7	1936	0	15	32.07	0	7
8	1937	0	17	28.29	0	8
9	1938	0	17	28.29	0	9
10	1939	0	17	28.29	0	10
11	1940	0	17	28.29	0	11
12	1941	0	18	26.72	0	12
13	1942	0	19	25.32	0	13
14	1943	0	19	25.32	0	14
15	1944	0	19	25.32	0	15
16	1945	0	19	25.32	0	16
17	1946	0	21	22.90	0	17
18	1947	0	24	20.04	0	18
19	1948	0	26	18.50	0	19
20	1949	0	28	17.18	0	20
21	1950	0	30	16.03	0	21
22	1951	0	31	15.52	0	22
23	1952	0	33	14.58	0	23
24	1953	0	34	14.15	0	24
25	1954	0	36	13.36	0	25
26	1955	0	37	13.00	0	26
27	1956	0	39	12.33	0	27
28	1957	0	41	11.73	0	28
29	1958	0	42	11.45	0	29
30	1959	0	45	10.69	0	30
31	1960	0	46	10.46	0	31
32	1961	0	49	9.82	0	32
33	1962	0	51	9.43	0	33
34	1963	0	52	9.25	0	34
35	1964	0	54	8.91	0	35
36	1965	0	57	8.44	0	36
37	1966	0	58	8.29	0	37
38	1967	0	62	7.76	0	38
39	1968	0	64	7.52	0	39
40	1969	0	69	6.97	0	40
41	1970	0	78	6.17	0	41
42	1971	0	88	5.47	0	42
43	1972	0	95	5.06	0	43
44	1973	0	100	4.81	0	44
45	1974	0	109	4.41	0	45
46	1975	0	122	3.94	0	46
47	1976	0	131	3.67	0	47
48	1977	0	142	3.39	0	48
49	1978	0	151	3.19	0	49
50	1979	0	160	3.01	0	50
51	1980	0	170	2.83	0	51
52	1981	0	185	2.60	0	52
53	1982	0	206	2.33	0	53
54	1983	0	218	2.21	0	54
55	1984	0	220	2.19	0	55
56	1985	0	214	2.25	0	56
57	1986	0	215	2.24	0	57
58	1987	0	216	2.23	0	58
59	1988	0	215	2.24	0	59
60	1989	0	214	2.25	0	60
61	1990	0	220	2.19	0	61
62	1991	0	225	2.14	0	62
63	1992	0	232	2.07	0	63
64	1993	0	236	2.04	0	64
65	1994	0	239	2.01	0	65
66	1995	0	247	1.95	0	66
67	1996	0	254	1.89	0	67
68	1997	0	257	1.87	0	68
69	1998	0	265	1.82	0	69
70	1999	0	275	1.75	0	70
71	2000	0	285	1.69	0	71
72	2001	0	299	1.61	0	72
73	2002	0	309	1.56	0	73
74	2003	0	318	1.51	0	74
75	2004	53,733	327	1.47	78,988	75
76	2005	417,383	337	1.43	596,858	76
77	2006	41,782	345	1.39	58,077	77
78	2007	0	354	1.36	0	78
79	2008	405,459	365	1.32	535,206	79
80	2009	1,742,481	382	1.26	2,195,526	80
81	2010	193,611	406	1.18	228,461	81
82	2011	594,238	416	1.16	689,316	82
83	2012	919,185	424	1.13	1,038,679	83
84	2013	1,046,489	429	1.12	1,172,068	84
85	2014	259,365	437	1.10	285,302	85
86	2015	16,807	445	1.08	18,152	86
87	2016	47,258	449	1.07	50,566	87
88	2017	0	473	1.02	0	88
89	2018	292,545	481	1.00	292,545	89
90	2019	0	481	1.00	0	90
91	Total	$ 6,030,336			$ 7,239,744	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

	Account 397.2 - Telemetry Equipment					
Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	15	32.07	$ 0	1
2	1931	0	15	32.07	0	2
3	1932	0	15	32.07	0	3
4	1933	0	15	32.07	0	4
5	1934	0	15	32.07	0	5
6	1935	0	15	32.07	0	6
7	1936	0	15	32.07	0	7
8	1937	0	17	28.29	0	8
9	1938	0	17	28.29	0	9
10	1939	0	17	28.29	0	10
11	1940	0	17	28.29	0	11
12	1941	0	18	26.72	0	12
13	1942	0	19	25.32	0	13
14	1943	0	19	25.32	0	14
15	1944	0	19	25.32	0	15
16	1945	0	19	25.32	0	16
17	1946	0	21	22.90	0	17
18	1947	0	24	20.04	0	18
19	1948	0	26	18.50	0	19
20	1949	0	28	17.18	0	20
21	1950	0	30	16.03	0	21
22	1951	0	31	15.52	0	22
23	1952	0	33	14.58	0	23
24	1953	0	34	14.15	0	24
25	1954	0	36	13.36	0	25
26	1955	0	37	13.00	0	26
27	1956	0	39	12.33	0	27
28	1957	0	41	11.73	0	28
29	1958	0	42	11.45	0	29
30	1959	0	45	10.69	0	30
31	1960	0	46	10.46	0	31
32	1961	0	49	9.82	0	32
33	1962	0	51	9.43	0	33
34	1963	0	52	9.25	0	34
35	1964	0	54	8.91	0	35
36	1965	0	57	8.44	0	36
37	1966	0	58	8.29	0	37
38	1967	0	62	7.76	0	38
39	1968	0	64	7.52	0	39
40	1969	0	69	6.97	0	40
41	1970	0	78	6.17	0	41
42	1971	0	88	5.47	0	42
43	1972	0	95	5.06	0	43
44	1973	0	100	4.81	0	44
45	1974	0	109	4.41	0	45
46	1975	0	122	3.94	0	46
47	1976	0	131	3.67	0	47
48	1977	0	142	3.39	0	48
49	1978	0	151	3.19	0	49
50	1979	0	160	3.01	0	50
51	1980	0	170	2.83	0	51
52	1981	0	185	2.60	0	52
53	1982	0	206	2.33	0	53
54	1983	0	218	2.21	0	54
55	1984	0	220	2.19	0	55
56	1985	0	214	2.25	0	56
57	1986	0	215	2.24	0	57
58	1987	0	216	2.23	0	58
59	1988	0	215	2.24	0	59
60	1989	0	214	2.25	0	60
61	1990	0	220	2.19	0	61
62	1991	0	225	2.14	0	62
63	1992	0	232	2.07	0	63
64	1993	0	236	2.04	0	64
65	1994	0	239	2.01	0	65
66	1995	0	247	1.95	0	66
67	1996	0	254	1.89	0	67
68	1997	0	257	1.87	0	68
69	1998	0	265	1.82	0	69
70	1999	0	275	1.75	0	70
71	2000	0	285	1.69	0	71
72	2001	0	299	1.61	0	72
73	2002	0	309	1.56	0	73
74	2003	0	318	1.51	0	74
75	2004	0	327	1.47	0	75
76	2005	0	337	1.43	0	76
77	2006	0	345	1.39	0	77
78	2007	0	354	1.36	0	78
79	2008	0	365	1.32	0	79
80	2009	0	382	1.26	0	80
81	2010	0	406	1.18	0	81
82	2011	0	416	1.16	0	82
83	2012	0	424	1.13	0	83
84	2013	0	429	1.12	0	84
85	2014	2,241	437	1.10	2,465	85
86	2015	0	445	1.08	0	86
87	2016	0	449	1.07	0	87
88	2017	0	473	1.02	0	88
89	2018	0	481	1.00	0	89
90	2019	0	481	1.00	0	90
91	Total	$ 2,241			$ 2,465	91

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
RCN COST OF GAS PLANT IN SERVICE AS OF JANUARY 31, 2019

Account 398 - Miscellaneous Equipment

Line No.	Year Installed (a)	Original Cost (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Cost (e)	Line No.
1	1930	$ 0	15	32.07	$ 0	1
2	1931	0	15	32.07	0	2
3	1932	0	15	32.07	0	3
4	1933	0	15	32.07	0	4
5	1934	0	15	32.07	0	5
6	1935	0	15	32.07	0	6
7	1936	0	15	32.07	0	7
8	1937	0	17	28.29	0	8
9	1938	0	17	28.29	0	9
10	1939	0	17	28.29	0	10
11	1940	0	17	28.29	0	11
12	1941	0	18	26.72	0	12
13	1942	0	19	25.32	0	13
14	1943	0	19	25.32	0	14
15	1944	0	19	25.32	0	15
16	1945	0	19	25.32	0	16
17	1946	0	21	22.90	0	17
18	1947	0	24	20.04	0	18
19	1948	0	26	18.50	0	19
20	1949	0	28	17.18	0	20
21	1950	0	30	16.03	0	21
22	1951	0	31	15.52	0	22
23	1952	0	33	14.58	0	23
24	1953	0	34	14.15	0	24
25	1954	0	36	13.36	0	25
26	1955	0	37	13.00	0	26
27	1956	0	39	12.33	0	27
28	1957	0	41	11.73	0	28
29	1958	0	42	11.45	0	29
30	1959	0	45	10.69	0	30
31	1960	0	46	10.46	0	31
32	1961	0	49	9.82	0	32
33	1962	0	51	9.43	0	33
34	1963	0	52	9.25	0	34
35	1964	0	54	8.91	0	35
36	1965	0	57	8.44	0	36
37	1966	0	58	8.29	0	37
38	1967	0	62	7.76	0	38
39	1968	0	64	7.52	0	39
40	1969	0	69	6.97	0	40
41	1970	0	78	6.17	0	41
42	1971	0	88	5.47	0	42
43	1972	0	95	5.06	0	43
44	1973	0	100	4.81	0	44
45	1974	0	109	4.41	0	45
46	1975	0	122	3.94	0	46
47	1976	0	131	3.67	0	47
48	1977	0	142	3.39	0	48
49	1978	0	151	3.19	0	49
50	1979	0	160	3.01	0	50
51	1980	0	170	2.83	0	51
52	1981	0	185	2.60	0	52
53	1982	0	206	2.33	0	53
54	1983	0	218	2.21	0	54
55	1984	0	220	2.19	0	55
56	1985	0	214	2.25	0	56
57	1986	0	215	2.24	0	57
58	1987	0	216	2.23	0	58
59	1988	0	215	2.24	0	59
60	1989	0	214	2.25	0	60
61	1990	0	220	2.19	0	61
62	1991	0	225	2.14	0	62
63	1992	0	232	2.07	0	63
64	1993	0	236	2.04	0	64
65	1994	0	239	2.01	0	65
66	1995	0	247	1.95	0	66
67	1996	0	254	1.89	0	67
68	1997	0	257	1.87	0	68
69	1998	0	265	1.82	0	69
70	1999	0	275	1.75	0	70
71	2000	0	285	1.69	0	71
72	2001	0	299	1.61	0	72
73	2002	0	309	1.56	0	73
74	2003	0	318	1.51	0	74
75	2004	7,002	327	1.47	10,293	75
76	2005	36,478	337	1.43	52,164	76
77	2006	88,395	345	1.39	122,869	77
78	2007	8,989	354	1.36	12,225	78
79	2008	42,617	365	1.32	56,254	79
80	2009	67,498	382	1.26	85,047	80
81	2010	83,004	406	1.18	97,945	81
82	2011	38,936	416	1.16	45,166	82
83	2012	32,528	424	1.13	36,757	83
84	2013	14,287	429	1.12	16,001	84
85	2014	315,147	437	1.10	346,662	85
86	2015	115,696	445	1.08	124,952	86
87	2016	272,684	449	1.07	291,772	87
88	2017	71,238	473	1.02	72,663	88
89	2018	97,539	481	1.00	97,539	89
90	2019	0	481	1.00	0	90
91	Total	$ 1,292,038			$ 1,468,309	91
92	Grand Total	$ 87,265,254			$ 107,633,979	92

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF RCND RESERVE BASED ON GAS PLANT IN SERVICE
AS OF JANUARY 31, 2019

Line No.	Description		Arizona		System Allocable	Line No.
	(a)		(b)		(c)	
			Company Records		Company Records	
	Gas Plant In Service					
1	Intangible Plant	$	4,219,850	$	237,589,747	1
2	Storage Plant		1,772,673		0	2
3	Distribution Plant		3,532,384,830		0	3
4	General Plant		166,198,282		87,265,254	4
5	Total Gas Plant In Service	$	3,704,575,635	$	324,855,001	5
	Accumulated Provision					
6	Intangible Plant	$	3,009,220	$	193,658,510	6
7	Storage Plant		0		0	7
8	Distribution Plant		1,358,231,289		0	8
9	General Plant		55,318,083		28,791,456	9
10	Total Accumulated Provision	$	1,416,558,592	$	222,449,966	10
	Percentage of Accumulated Reserve to Gas Plant In Service					
11	Intangible Plant		71.31%		81.51%	11
12	Storage Plant		0.00%		N/A	12
13	Distribution Plant		38.45%		N/A	13
14	General Plant		33.28%		32.99%	14

Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
RCN DEFERRED TAXES BY VINTAGE
AT JANUARY 31, 2019

		Arizona			System Allocable						RCN Deferred Taxes			
Line No.	Year	Total Federal 282 Deferred Tax Liability at 1/31/19	Total State 282 Deferred Tax Liability at 1/31/19	Total Arizona Deferred Tax Liability at 1/31/19	Total Federal 282 Deferred Tax Liability at 1/31/19	Total Acct 190 Deferred Tax Liability at 1/31/19	Total System Allocable at 1/31/19	4-Factor	Total Recorded Deferred Tax Liability at 1/31/19	Total AZ Recorded Deferred Tax Liability at 1/31/19	H - W Index	Ratio to Current Index	RCN Deferred Taxes for Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
		Company Records	Company Records	(b) + (c)	Company Records	Company Records	(e) + (f)	Sch C-1, Sh 17, Ln 9(c)	(g) * (h)	(d) + (i)	Company Records	Ln 62(k) / (k)	(j) * (l)	
1	1958	$ (311)	$ (57)	$ (368)	$ 0	$ 0	$ 0	55.68%	$ 0	$ (368)	61	12.47	$ (4,589)	1
2	1959	0	0	0	0	0	0	55.68%	0	0	63	12.07	0	2
3	1960	0	0	0	0	0	0	55.68%	0	0	65	11.70	0	3
4	1961	0	0	0	0	0	0	55.68%	0	0	66	11.52	0	4
5	1962	0	0	0	0	0	0	55.68%	0	0	67	11.35	0	5
6	1963	0	0	0	0	0	0	55.68%	0	0	68	11.18	0	6
7	1964	0	0	0	0	0	0	55.68%	0	0	69	11.02	0	7
8	1965	(4)	(1)	(5)	0	0	0	55.68%	0	(5)	71	10.71	(54)	8
9	1966	0	0	0	0	0	0	55.68%	0	0	72	10.56	0	9
10	1967	0	0	0	0	0	0	55.68%	0	0	74	10.28	0	10
11	1968	0	0	0	0	0	0	55.68%	0	0	76	10.01	0	11
12	1969	0	(1,334)	(1,334)	(12,981)	0	(12,981)	55.68%	(7,228)	(8,562)	79	9.63	(82,452)	12
13	1970	0	0	0	0	0	0	55.68%	0	0	84	9.05	0	13
14	1971	(1,030)	(193)	(1,223)	0	0	0	55.68%	0	(1,223)	90	8.45	(10,334)	14
15	1972	(8,224)	(1,510)	(9,734)	0	0	0	55.68%	0	(9,734)	95	8.01	(77,969)	15
16	1973	(3,444)	(629)	(4,073)	0	0	0	55.68%	0	(4,073)	100	7.61	(30,996)	16
17	1974	306	55	361	0	0	0	55.68%	0	361	115	6.61	2,386	17
18	1975	(118)	(19)	(137)	0	0	0	55.68%	0	(137)	133	5.72	(784)	18
19	1976	(47)	(10)	(57)	0	0	0	55.68%	0	(57)	143	5.32	(303)	19
20	1977	(221)	(45)	(266)	0	0	0	55.68%	0	(266)	155	4.91	(1,306)	20
21	1978	3,295	606	3,901	0	0	0	55.68%	0	3,901	169	4.50	17,555	21
22	1979	1,152,044	214,748	1,366,792	0	0	0	55.68%	0	1,366,792	184	4.13	5,644,851	22
23	1980	85,699	16,635	102,334	0	0	0	55.68%	0	102,334	198	3.84	392,963	23
24	1981	65,983	12,441	78,424	0	0	0	55.68%	0	78,424	223	3.41	267,426	24
25	1982	77,421	14,350	91,771	0	0	0	55.68%	0	91,771	235	3.24	297,338	25
26	1983	53,802	9,942	63,744	1,594	0	1,594	55.68%	888	64,632	241	3.16	204,237	26
27	1984	1,663,044	306,171	1,969,215	26,165	0	26,165	55.68%	14,568	1,983,783	246	3.09	6,129,889	27
28	1985	827,214	154,057	981,271	4,347	0	4,347	55.68%	2,420	983,691	241	3.16	3,108,464	28
29	1986	987,121	178,358	1,165,479	1,278	0	1,278	55.68%	712	1,166,191	234	3.25	3,790,121	29
30	1987	978,548	178,791	1,157,339	0	0	0	55.68%	0	1,157,339	242	3.14	3,634,044	30
31	1988	1,258,305	231,340	1,489,645	0	0	0	55.68%	0	1,489,645	255	2.98	4,439,142	31
32	1989	784,649	170,248	954,897	247,152	0	247,152	55.68%	137,609	1,092,506	264	2.88	3,146,417	32
33	1990	586,560	106,927	693,487	6,375	0	6,375	55.68%	3,549	697,036	271	2.81	1,958,671	33
34	1991	441,373	81,508	522,881	3,544	0	3,544	55.68%	1,973	524,854	278	2.74	1,438,100	34
35	1992	820,960	151,014	971,974	2,535	0	2,535	55.68%	1,411	973,385	283	2.69	2,618,406	35
36	1993	1,546,639	282,874	1,829,513	4,829	0	4,829	55.68%	2,689	1,832,202	291	2.61	4,782,047	36
37	1994	1,843,864	337,336	2,181,200	4,626	0	4,626	55.68%	2,576	2,183,776	307	2.48	5,415,764	37
38	1995	2,853,924	526,327	3,380,251	4,852	0	4,852	55.68%	2,701	3,382,952	309	2.46	8,322,062	38
39	1996	3,289,155	606,724	3,895,879	0	0	0	55.68%	0	3,895,879	312	2.44	9,505,945	39
40	1997	3,214,658	591,658	3,806,316	1,389	0	1,389	55.68%	773	3,807,089	320	2.38	9,060,872	40
41	1998	4,305,605	798,174	5,103,779	37,627	0	37,627	55.68%	20,950	5,124,729	323	2.35	12,043,113	41
42	1999	5,471,615	1,005,333	6,476,948	14,170	0	14,170	55.68%	7,890	6,484,838	331	2.30	14,915,127	42
43	2000	4,713,493	866,626	5,580,119	57,304	0	57,304	55.68%	31,906	5,612,025	346	2.20	12,346,455	43
44	2001	5,570,593	1,015,511	6,586,104	206,399	0	206,399	55.68%	114,918	6,701,022	352	2.16	14,474,208	44
45	2002	6,826,019	1,161,876	7,987,895	84,217	0	84,217	55.68%	46,890	8,034,785	358	2.12	17,033,744	45
46	2003	8,288,979	1,385,674	9,674,653	93,872	0	93,872	55.68%	52,266	9,726,919	373	2.04	19,842,915	46
47	2004	10,231,669	1,507,728	11,739,397	165,961	0	165,961	55.68%	92,403	11,831,800	439	1.73	20,469,014	47
48	2005	7,534,006	1,420,640	8,954,646	391,263	0	391,263	55.68%	217,846	9,172,492	517	1.47	13,483,563	48
49	2006	6,530,408	1,232,374	7,762,782	293,998	0	293,998	55.68%	163,691	7,926,473	529	1.44	11,414,121	49
50	2007	7,644,217	1,421,961	9,066,178	241,006	0	241,006	55.68%	134,187	9,200,365	518	1.47	13,524,537	50
51	2008	11,770,389	1,742,480	13,512,869	228,585	0	228,585	55.68%	127,271	13,640,140	578	1.31	17,868,583	51
52	2009	10,389,057	1,592,828	11,981,885	154,381	0	154,381	55.68%	85,956	12,067,841	581	1.31	15,808,872	52
53	2010	12,870,400	1,802,582	14,672,982	184,267	0	184,267	55.68%	102,596	14,775,578	603	1.26	18,617,228	53
54	2011	25,537,460	2,374,097	27,911,557	1,419,058	(17,410,908)	(15,991,850)	55.68%	(8,903,894)	19,007,663	670	1.14	21,668,736	54
55	2012	18,463,425	2,282,789	20,746,214	389,055	(918,427)	(529,372)	55.68%	(294,742)	20,451,472	722	1.05	21,474,046	55
56	2013	13,995,863	1,543,310	15,539,173	1,259,495	(1,398,037)	(138,542)	55.68%	(77,137)	15,462,036	714	1.07	16,544,379	56
57	2014	20,052,184	2,089,709	22,141,893	3,435,806	(527,027)	2,908,779	55.68%	1,619,541	23,761,434	716	1.06	25,187,120	57
58	2015	25,885,502	2,121,284	28,006,786	1,534,633	(2,102,736)	(568,103)	55.68%	(316,307)	27,690,479	699	1.09	30,182,622	58
59	2016	20,092,900	1,975,719	22,068,619	3,703,888	(216,585)	3,487,303	55.68%	1,941,650	24,010,269	693	1.10	26,411,296	59
60	2017	37,640,952	2,546,454	40,187,406	2,048,796	0	2,048,796	55.68%	1,140,722	41,328,128	728	1.05	43,394,534	60
61	2018	11,643,788	2,029,148	13,672,936	1,750,015	0	1,750,015	55.68%	974,368	14,647,304	761	1.00	14,647,304	61
62	2019	45,754	24,700	70,454	153,671	0	153,671	55.68%	85,560	156,014	761	1.00	156,014	62
63	Total	$ 298,025,443	$ 38,109,309	$ 336,134,752	$ 18,143,172	$ (22,573,720)	$ (4,430,548)		$ (2,466,828)	$ 333,667,924			$ 475,475,444	63
64											Excess Deferred Taxes		191,480,731	64
65											Deferred Tax Adjustments		(1,518,173)	65
66											Total RCND Deferred Taxes		$ 665,438,002	66
													Sch B-1, Sh 1, Ln 13(d)	

SOUTHWEST GAS CORPORATION
ARIZONA
WORKING CAPITAL ALLOWANCE COMPUTATION
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Reference		Amount	Line No.
	(a)	(b)		(c)	
1	Cash Working Capital	Sch B-5, Sh 2, Ln 15(c)	$	(10,297,032)	1
2	Materials and Supplies	Sch B-5, Sh 3, Ln 16(f)		34,013,908	2
3	Prepayments	Sch B-5, Sh 4, Ln 19(h)		7,721,011	3
4	Total Working Capital Allowance	Sum Lns 1-3	$	31,437,887	4
				Sch B-1, Sh 2, Lns 8-10	

SOUTHWEST GAS CORPORATION
ARIZONA
CASH WORKING CAPITAL
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Reference		Cost	Lag Days		Dollar Days	Line No.
	(a)	(b)		(c)	(d)		(e)	
							(c) * (d)	
1	Cost of Gas	[1]	$	181,599,453	37.85	$	6,873,779,606	1
2	Labor and Benefits Expense	WP B-5, Sh 14		130,926,194	10.93		1,430,464,753	2
3	Prepayments Amortized to O&M	WP B-5, Sh 29		92,279,096	0.00		0	3
4	Uncollectibles Expense	WP B-5, Sh 28		1,350,724	90.83		122,690,764	4
5	Other O&M Expense	WP B-5, Sh 28		7,188,668	15.39		110,618,672	5
6	Total O&M Expense	Sum Lns 1-5	$	413,344,135	20.65	$	8,537,553,794	6
7	Interest	Sch C-1, Sh 16, Ln 21(e)		47,329,818	84.97		4,021,573,582	7
8	Taxes Other than Income Taxes	Sch A-1, Sh 2, Ln 15(g)		58,155,759	165.45		9,622,073,434	8
9	Income Taxes - Current	Sch C-1, Sh 16, Ln 18(e)		15,482,271	35.75		553,491,172	9
10	Total	Sum Lns 6-9	$	534,311,983	42.55	$	22,734,691,982	10
11	Number of Days in Test Period			365				11
12	Average Daily Operating Expenses	Ln 10 / Ln 11	$	1,463,868				12
13	Lag in Receipt of Revenue	WP B-5, Sh 93, Ln 4(c)			35.52			13
14	Net Revenue Lag (Expense Lead)	Ln 13(d) - Ln 10(d)		(7.03)				14
15	Cash Working Capital	Ln 12 * Ln 14	$	(10,297,032)				15
				Sch B-5, Sh 1, Ln 1(c)				

[1] Gas Costs adjusted for present volumes and rates.

SOUTHWEST GAS CORPORATION
ARIZONA
MATERIALS AND SUPPLIES (M&S) [1]
FOR THE THIRTEEN MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Reference	Account Number 154	Account Number 163	System Allocable	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
			Company Records	Company Records	WP B-5, Sh 1	Sum (c)-(e)	
1	January 2018		$ 25,276,794	$ 709,217	$ (7,846)	$ 25,978,165	1
2	February 2018		28,230,028	760,325	(7,665)	28,982,689	2
3	March 2018		30,255,746	1,271,196	(7,475)	31,519,466	3
4	April 2018		32,079,212	981,737	(7,472)	33,053,477	4
5	May 2018		33,512,886	737,995	(6,601)	34,244,280	5
6	June 2018		34,927,370	581,162	(6,830)	35,501,703	6
7	July 2018		34,510,820	594,705	(44,382)	35,061,143	7
8	August 2018		33,344,490	557,227	(42,594)	33,859,123	8
9	September 2018		33,078,563	572,125	(42,487)	33,608,200	9
10	October 2018		34,201,178	481,222	17,567	34,699,966	10
11	November 2018		36,510,606	574,174	(42,120)	37,042,660	11
12	December 2018		37,988,061	529,886	(42,032)	38,475,915	12
13	January 2019		39,891,183	304,861	(42,032)	40,154,013	13
14	Thirteen Month Total	Sum Lns 1-13	$ 433,806,935	$ 8,655,833	$ (281,968)	$ 442,180,800	14
15	Thirteen Month Average	Ln 14 / 13	$ 33,369,764	$ 665,833	$ (21,690)	$ 34,013,908	15
16	Test Year M&S	Ln 15				$ 34,013,908	16
						Sch B-5, Sh 1, Ln 2	

[1] $2.8M of LNG inventory is added to test year M&S in Adjustment No. 18.

SOUTHWEST GAS CORPORATION
ARIZONA
PREPAYMENTS
FOR THE THIRTEEN MONTHS ENDED JANUARY 31, 2019

Line No.	Description (a)	Reference (b)	Postage 165000000 (c) Company Records	Insurance and Other 165001129 (d) Company Records	Licenses and Franchise Taxes 165001131 (e) Company Records	Prepaid Supplies-General Office 165001132 (f) Company Records	Commercial Paper Facility 165001353 (g) Company Records	Total (h) Sum (c)-(g)	Line No.
1	January 2018		$ 896,341	$ 10,778,884	$ 0	$ 44,627	$ 42,139	$ 11,761,992	1
2	February 2018		1,117,596	10,895,430	0	42,003	7,250	12,062,278	2
3	March 2018		1,281,233	9,387,554	0	36,778	24,347	10,729,913	3
4	April 2018		1,475,457	8,217,138	0	38,905	0	9,731,500	4
5	May 2018		884,053	7,559,468	0	39,036	0	8,482,557	5
6	June 2018		323,634	8,915,102	2,042,981	34,543	0	11,316,261	6
7	July 2018		533,334	14,714,585	0	38,488	0	15,286,408	7
8	August 2018		683,146	15,624,132	0	39,932	23,819	16,371,029	8
9	September 2018		201,861	18,834,863	0	50,968	20,243	19,107,934	9
10	October 2018		1,105,003	15,554,618	0	55,194	36,771	16,751,587	10
11	November 2018		624,086	15,933,910	0	53,987	43,889	16,655,872	11
12	December 2018		863,550	16,099,241	0	49,732	34,667	17,047,190	12
13	January 2019		1,044,023	16,575,551	0	43,523	51,806	17,714,903	13
14	Thirteen Month Total	Sum Lns 1-13	$ 11,033,319	$ 169,090,477	$ 2,042,981	$ 567,716	$ 284,931	$ 183,019,424	14
15	Thirteen Month Average	Ln 14 / 13	$ 848,717	$ 13,006,960	$ 157,152	$ 43,670	$ 21,918	$ 14,078,417	15
16	Deferred Taxes	Ln 15 * Sch C-3, Sh 2, Ln 4(c)	211,084	0	0	0	0	211,084	16
17	Balance Net of Deferred Taxes	Ln 15 - Ln 16	$ 637,632	$ 13,006,960	$ 157,152	$ 43,670	$ 21,918	$ 13,867,333	17
18	AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)						55.68%	18
19	Prepayments Allocated to AZ	Ln 17 * Ln 18						$ 7,721,011	19
								Sch B-5, Sh 1, Ln 3	

SOUTHWEST GAS CORPORATION
ARIZONA
CUSTOMER DEPOSITS
FOR THE THIRTEEN MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Reference	Account 235 Balance	Line No.
	(a)	(b)	(c)	
			Company Records	
1	January 2018		$ 37,419,164	1
2	February 2018		37,387,707	2
3	March 2018		37,219,341	3
4	April 2018		37,238,343	4
5	May 2018		37,190,473	5
6	June 2018		37,265,701	6
7	July 2018		37,019,683	7
8	August 2018		36,730,800	8
9	September 2018		36,490,283	9
10	October 2018		36,290,125	10
11	November 2018		36,213,466	11
12	December 2018		36,256,300	12
13	January 2019		36,495,586	13
14	Thirteen Month Total	Sum Lns 1-13	$ 479,216,972	14
15	Thirteen Month Average	Ln 14 / 13	$ 36,862,844	15
16	Test Year Customer Deposits	Ln 15	$ 36,862,844	16
			Sch B-1, Sh 2, Ln 11(c)	

SOUTHWEST GAS CORPORATION
ARIZONA
CUSTOMER ADVANCES
FOR THE THIRTEEN MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Reference		Account 252 Balance	Line No.
	(a)	(b)		(c)	
				Company Records	
1	January 2018		$	37,265,177	1
2	February 2018			38,149,009	2
3	March 2018			38,553,917	3
4	April 2018			39,549,617	4
5	May 2018			41,085,784	5
6	June 2018			41,409,771	6
7	July 2018			41,043,929	7
8	August 2018			42,663,577	8
9	September 2018			44,165,493	9
10	October 2018			44,282,685	10
11	November 2018			43,999,864	11
12	December 2018			44,443,844	12
13	January 2019			44,361,607	13
14	Thirteen Month Total	Sum Lns 1-13	$	540,974,274	14
15	Thirteen Month Average	Ln 14 / 13	$	41,613,406	15
16	Test Year Customer Advances	Ln 15	$	41,613,406	16
				Sch B-1, Sh 2, Ln 12(c)	

SOUTHWEST GAS CORPORATION
ARIZONA
DEFERRED TAXES AS RECORDED
AT JANUARY 31, 2019

Line No.	Description	Reference	AZ Direct	System Allocable	After 4-Factor Allocation	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
			Company Records	Company Records	Col (d) * Ln 6(e)	(c) + (e)	
1	Deferred Tax Liability - State	Account 282	$ 36,034,057	$ 3,727,259	$ 2,075,252	$ 38,109,309	1
2	Deferred Tax Liability - Federal	Account 282	298,025,443	18,143,172	10,101,700	308,127,143	2
3	Excess Deferred Income Taxes	Account 254	186,630,306	8,744,231	4,850,425	191,480,731	3
4	Alternative Minimum Tax	Account 190	0	(22,573,720)	(12,568,527)	(12,568,527)	4
5	Total	Sum Lns 1 - 4	$ 520,689,806	$ 8,040,942	$ 4,458,850	$ 525,148,656	5
						Sch B-1, Sh 2, Ln 13(c)	
6	AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)			55.68%		6

SOUTHWEST GAS CORPORATION
ARIZONA
DEFERRED TAXES AS ADJUSTED
AT JANUARY 31, 2019

Line No.	Description	Reference	AZ Direct	System Allocable	After 4-Factor Allocation	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
					Col (d) * Ln 16(e)	(c) + (e)	
	As Recorded						
1	Deferred Tax Liability - State	Sch B-6, Sh 3, Ln 1	$ 36,034,057	$ 3,727,259	$ 2,075,252	$ 38,109,309	1
2	Deferred Tax Liability - Federal	Sch B-6, Sh 3, Ln 2	298,025,443	18,143,172	10,101,700	308,127,143	2
3	Excess Deferred Income Taxes	Sch B-6, Sh 3, Ln 3	186,630,306	8,744,231	4,850,425	191,480,731	3
4	Alternative Minimum Tax	Sch B-6, Sh 3, Ln 4	0	(22,573,720)	(12,568,527)	(12,568,527)	4
5	Total	Sum Lns 1 - 4	$ 520,689,806	$ 8,040,942	$ 4,458,850	$ 525,148,656	5
	Adjustments						
6	Deferred Tax Liability - State	B-2, Adj. 19, Sh 1	$ 60,077	$ (104,893)	$ (58,402)	$ 1,675	6
7	Deferred Tax Liability - Federal	B-2, Adj. 19, Sh 1	(1,209,106)	(558,109)	(310,742)	(1,519,848)	7
8	Excess Deferred Income Taxes	B-2, Adj. 19, Sh 1	0	0	0	0	8
9	Alternative Minimum Tax	B-2, Adj. 19, Sh 1	0	0	0	0	9
10	Total	Sum Lns 6 - 9	$ (1,149,029)	$ (663,002)	$ (369,144)	$ (1,518,173)	10
						Sch C-2, Sh 2, Col (j)	
	As Adjusted						
11	Deferred Tax Liability - State	Ln 1 + Ln 6	$ 36,094,134	$ 3,622,366	$ 2,016,850	$ 38,110,984	11
12	Deferred Tax Liability - Federal	Ln 2 + Ln 7	296,816,337	17,585,063	9,790,958	306,607,295	12
13	Excess Deferred Income Taxes	Ln 3 + Ln 8	186,630,306	8,744,231	4,850,425	191,480,731	13
14	Alternative Minimum Tax	Ln 4 + Ln 9	0	(22,573,720)	(12,568,527)	(12,568,527)	14
15	Total	Sum Lns 11 - 14	$ 519,540,778	$ 7,377,940	$ 4,089,706	$ 523,630,483	15
16	AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)			55.68%		16

SOUTHWEST GAS CORPORATION
ARIZONA
EXCESS ACCUMULATED DEFERRED INCOME TAXES
REGULATORY LIABILITY

Line No.	Description	Reference	Plant Amount	Non-Plant Amount	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	
					(c) + (d)	
1	Timing Differences at 12/31/2017	Company Records	$ 1,351,653,336	$ 13,780,775	$ 1,365,434,111	1
2	Recorded Deferred Taxes	Ln 1 * 21%	$ 283,847,201	$ 2,893,963	$ 286,741,163	2
3	Required Deferred Taxes at 35% Statutory Rate	Ln 1 * 35%	473,078,668	4,823,271	477,901,939	3
4	Excess Deferred Taxes Before State Adjustment	Ln 3 - Ln 2	$ 189,231,467	$ 1,929,309	$ 191,160,776	4
5	State Adjustment (Federal Benefit of State Taxes)	Company Records	(2,601,161)	(55,796)	(2,656,957)	5
6	Excess Deferred Taxes	Ln 4 + Ln 5	$ 186,630,306	$ 1,873,513	$ 188,503,819	6
7	Common Excess Deferred Taxes Allocated to Arizona	Ln 18	4,850,425	(2,903,739)	1,946,686	7
8	Total Arizona Excess Deferred Taxes [1]	Ln 6 + Ln 7	$ 191,480,731	$ (1,030,226)	$ 190,450,505	8
9	Gross-up [2]	Company Records	58,117,877	(312,692)	57,805,185	9
10	Total Arizona Regulatory Liability	Ln 8 + Ln 9	$ 249,598,609	$ (1,342,918)	$ 248,255,690	10
			Sch B-6, Sh 6, Ln 1(c)	Sch B-6, Sh 6, Ln 1(d)		
	SYSTEM ALLOCABLE					
11	Timing Differences at 12/31/2017	Company Records	$ 65,175,852	$ (38,504,933)	$ 26,670,919	11
12	Recorded Deferred Taxes	Ln 11 * 21%	13,686,929	(8,086,036)	5,600,893	12
13	Required Deferred Taxes at 35% Statutory Rate	Ln 11 * 35%	22,811,548	(13,476,727)	9,334,822	13
14	Excess Deferred Taxes Before State Adjustment	Ln 13 - Ln 12	$ 9,124,619	$ (5,390,691)	$ 3,733,929	14
15	State Adjustment (Federal Benefit of State Taxes)	Company Records	(380,388)	155,899	(224,489)	15
16	Excess Deferred Taxes	Ln 14 + Ln 15	$ 8,744,231	$ (5,234,791)	$ 3,509,440	16
17	4-Factor at 12/31/17 [3]		55.47%	55.47%	55.47%	17
18	Excess Deferred Taxes Apportioned to Arizona	Ln 16 * Ln 17	$ 4,850,425	$ (2,903,739)	$ 1,946,686	18

[1] Rate Base adjustment associated with plant-related excess deferred income tax
[2] Excess deferred taxes are grossed-up to reflect the future tax savings of reduced future revenue
[3] The 4-factor percentage used to establish the excess deferred liability is the percentage at 12/31/17

SOUTHWEST GAS CORPORATION
ARIZONA
AMORTIZATION OF EXCESS ACCUMULATED DEFERRED INCOME TAXES (EADIT)

Line No.	Description	Reference	Plant Amount	Non-Plant Amount	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	
					(c) + (d)	
1	Total Arizona Regulatory Liability (Asset)	Sch B-6, Sh 5, Ln 10	$ 249,598,609	$ (1,342,918)	$ 248,255,690	1
2	Amortization Period (Years)			3		2
3	Annual Amortization of EADIT	Company Records	$ 14,914,416			3
4	Arizona Share of System Allocable EADIT	Ln 8	991,382			4
5	Total Arizona Annual Amortization of EADIT [1]	Ln 3 + Ln 4	$ 15,905,798	$ (447,639)	15,458,159	5
					Sch C-1, Sh 16, Ln 15(d)	

SYSTEM ALLOCABLE

Line No.	Description	Reference	Plant Amount	Line No.
6	Annual Amortization of EADIT	Company Records	$ 1,787,240	6
7	4-Factor at 12/31/17	[2]	55.47%	7
8	Arizona Share of Annual Amortization of EADIT	Ln 6 * Ln 7	$ 991,382	8

[1] The regulatory liability will be reduced by the grossed-up amount.
[2] The 4-factor used to establish the excess deferred liability is the percentage at 12/31/17

SCHEDULE C

SOUTHWEST GAS CORPORATION
ARIZONA
ADJUSTED TEST YEAR INCOME STATEMENT
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Reference	Recorded 1/31/2019	Adjustments	Adjusted 1/31/2019	Line No.
	(a)	(b)	(c)	(d)	(e)	
				Sch C-2, Sh 2, Col (k)	(c) + (d)	
1	Operating Revenue	Sch C-2, Adj 1, Sh 1	$ 701,861,440	$ (183,643,076)	$ 518,218,363	1
2	Gas Cost	Sch C-1, Sh 3, Lns 6 and 9	201,173,630	(201,173,630)	0	2
3	Operating Margin	Ln 1 - Ln 2	$ 500,687,809	$ 17,530,554	$ 518,218,363	3
	Operating Expenses					
4	Other Gas Costs	Sch C-1, Sh 3, Ln 7(c)	$ 1,267,230	$ 90,917	$ 1,358,147	4
5	Storage	Sch C-1, Sh 3, Ln 8(c)	0	1,470,088	1,470,088	5
6	Distribution	Sch C-1, Sh 3, Ln 25(c)	106,965,636	1,996,392	108,962,028	6
7	Customer Accounts	Sch C-1, Sh 3, Ln 31(c)	24,864,595	783,894	25,648,489	7
8	Customer Service & Info.	Sch C-1, Sh 4, Ln 4(c)	424,773	(45,406)	379,366	8
9	Sales	Sch C-1, Sh 4, Ln 8(c)	12,629	(5,050)	7,579	9
	Administrative & General					
10	Direct	Sch C-1, Sh 9, Ln 25(d)	5,152,768	874,447	6,027,215	10
11	System Allocable	Sch C-1, Sh 9, Ln 25(k)	88,354,236	(572,485)	87,781,751	11
	Depreciation & Amortization					
12	Direct	Sch C-1, Sh 14, Ln 3(d)	90,541,589	10,835,680	101,377,269	12
13	System Allocable	Sch C-1, Sh 14, Ln 12(d)	11,134,978	3,544,503	14,679,481	13
14	Regulatory Amortizations	Sch C-1, Sh 14, Ln 6(d)	6,769,642	(10,198,917)	(3,429,275)	14
15	Taxes Other Than Income	Sch C-1, Sh 15, Ln 3(c)	42,244,348	15,911,411	58,155,759	15
16	Interest on Customer Deposits	Sch C-2, Adj. 15, Sh 1, Ln 4(c)	2,180,878	(1,222,444)	958,434	16
17	Income Taxes	Sch C-1, Sh 16, Ln 18(c)	19,091,352	(17,758,548)	1,332,804	17
18	Total Operating Expenses	Sum Lns 4-17	$ 399,004,654	$ 5,704,481	$ 404,709,135	18
19	Net Operating Income	Ln 3 - Ln 18	$ 101,683,155	$ 11,826,073	$ 113,509,228	19
			Sch A-1, Sh 2, Col (c)	Sch A-1, Sh 2, Col (d)	Sch A-1, Sh 2, Col (e)	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
ADJUSTED SALES VOLUMES AND REVENUES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Recorded At 01/31/2019	Adjustment No. 1	Test Period Balance As Adjusted	Line No.
	(a)	(b)	(c)	(d)	
1	Sales Quantity (Therms) [1]	529,437,882	(9,122,664)	520,315,218	1
2	Revenue [1]	$ 701,861,440	$ (183,643,076)	$ 518,218,363	2
3	Total Revenue Adjustment		$ (183,643,076)		3

[1] Schedule C-2, Adjustment No. 1, Sheet 1.

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATIONS AND MAINTENANCE EXPENSE SUMMARY
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description	Account No./ Reference	Recorded 1/31/2019	Adjustments	Adjusted 1/31/2019	Line No.
	(a)	(b)	(c)	(d)	(e)	
			Sch C-1, Sh 5-8, Col (c)	(e) - (c)	Sch C-1, Sh 5-8, Col (k)	
	Purchased Gas Costs					
1	Natural Gas Transmission Line Purchases	803	$ 116,448,762	$ (116,448,762)	$ 0	1
2	Purchased Gas Cost Adjustments	805	77,881,083	(77,881,083)	0	2
3	Gas Withdrawn From Storage	808	226,519	(226,519)	0	3
4	Gas Delivered To Storage	808	(16,523)	16,523	0	4
5	Gas Used for Compressor Station Fuel	810	0	0	0	5
6	Total Purchased Gas Costs	Sum Lns 1-5	$ 194,539,841	$ (194,539,841)	$ 0	6
	Other Gas Costs					
7	Other Gas Supply	813	$ 1,267,230	$ 90,917	$ 1,358,147	7
	Storage					
8	LNG Storage Facility	Various	$ 0	$ 1,470,088	$ 1,470,088	8
	Transmission					
9	Transmission and Compression of Gas by Others	858	$ 6,633,789	$ (6,633,789)	$ 0	9
	Distribution					
10	Operation Supervision and Engineering	870	$ 11,312,091	$ 144,185	$ 11,456,277	10
11	Operation Distribution Load Dispatching	871	633,468	42,095	675,562	11
12	Operation Mains and Services	874	12,418,223	155,358	12,573,581	12
13	Operation Measuring and Regulation Station	875	2,444,742	60,383	2,505,125	13
14	Operation Meter and House Regulator	878	10,488,868	254,436	10,743,304	14
15	Customer Installation	879	12,022,337	458,427	12,480,763	15
16	Other	880	12,968,364	164,993	13,133,357	16
17	Rents	881	(634,635)	(89,800)	(724,435)	17
18	Maintenance Supervision and Engineering	885	2,452,396	71,088	2,523,484	18
19	Maintenance of Structures and Improvements	886	78,366	573	78,938	19
20	Maintenance of Mains	887	23,811,700	386,386	24,198,086	20
21	Maintenance of Measuring and Reg. Station Eq.	889	2,514,812	61,846	2,576,658	21
22	Maintenance of Services	892	12,692,799	194,991	12,887,790	22
23	Maintenance of Meters and House Regulators	893	3,411,116	81,788	3,492,904	23
24	Maintenance of Other Equipment	894	350,988	9,645	360,633	24
25	Total Distribution	Sum Lns 10-24	$ 106,965,636	$ 1,996,392	$ 108,962,028	25
	Customer Accounts					
26	Supervision	901	$ 1,728,035	$ 114,926	$ 1,842,960	26
27	Meter Reading	902	1,516,106	41,194	1,557,300	27
28	Customer Records and Collection	903	20,070,871	704,938	20,775,809	28
29	Uncollectible Accounts	904	1,431,902	(81,178)	1,350,724	29
30	Miscellaneous	905	117,681	4,014	121,695	30
31	Total Customer Accounts	Sum Lns 26-30	$ 24,864,595	$ 783,894	$ 25,648,489	31

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATIONS AND MAINTENANCE EXPENSE SUMMARY
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description	Account No./ Reference	Recorded 1/31/2019	Adjustments	Adjusted 1/31/2019	Line No.
	(a)	(b)	(c)	(d)	(e)	
			Sch C-1, Sh 5-8, Col (c)	(e) - (c)	Sch C-1, Sh 5-8, Col (k)	
	Customer Service and Information					
1	Customer Assistance	908	$ 24,142	$ (24,163)	$ (21)	1
2	Informational and Instructional Advertising	909	0	0	0	2
3	Miscellaneous	910	400,631	(21,243)	379,388	3
4	Total Customer Service and Information	Sum Lns 1-3	$ 424,773	$ (45,406)	$ 379,366	4
	Sales					
5	Supervision	911	$ 0	$ 0	$ 0	5
6	Demonstration and Selling	912	0	0	0	6
7	Advertising	913	12,629	(5,050)	7,579	7
8	Total Sales	Sum Lns 5-7	$ 12,629	$ (5,050)	$ 7,579	8
9	Total O&M		$ 334,708,493	$ (196,882,796)	$ 137,825,696	9
	Administrative and General (A&G)		Sch C-1, Sh 9, Col (l)		Sch C-1, Sh 13, Col (l)	
10	A&G Salaries	920	$ 48,051,328	$ 1,609,230	$ 49,660,558	10
11	Office Supplies and Expenses	921	8,869,929	(215,871)	8,654,058	11
12	A&G Expenses Transferred (Credit)	922	(8,221,169)	(225,129)	(8,446,298)	12
13	Outside Services	923	14,730,167	(207,121)	14,523,045	13
14	Property Insurance	924	246,112	2,865	248,977	14
15	Injuries and Damages	925	7,393,088	548,550	7,941,638	15
16	Employee Pension and Benefits	926	10,996,799	(1,134,401)	9,862,398	16
17	Regulatory Commission Expenses	928	86,892	70,108	157,000	17
18	Safety Advertising	930.1	962,067	0	962,067	18
19	Miscellaneous General	930.2	4,313,280	(169,239)	4,144,041	19
20	Rents	931	1,888,613	(17,012)	1,871,601	20
21	Maintenance of General Plant	935	4,189,900	39,982	4,229,882	21
22	Total A&G	Sum Lns 10-21	$ 93,507,005	$ 301,962	$ 93,808,967	22
23	Total O&M and A&G	Ln 9 + Ln 22	$ 428,215,498	$ (196,580,834)	$ 231,634,663	23

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATIONS AND MAINTENANCE EXPENSE AS ADJUSTED
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description (a)	Account No. (b)	Recorded 1/31/2019 (c)	Purchased Gas Cost Adj. No. 2 (d)	Labor/Loading Annualization Adj. No. 3 (e) Sch C-2, Adj. 3, Sh 1, Cols (b)-(c)	Call Center & Customer Supp. Adj. No. 4 (f) Sch C-2, Adj. 4, Sh 1	Cost of Service Analysis Adj. No. 5 (g) Sch C-2, Adj. 5, Sh 1 Sch C-2, Adj. 5, Sh 2	Employee Vehicles Adj. No. 6 (h) Sch C-2, Adj. 6, Sh 2	Uncollectibles Annualization Adj. No. 7 (i) Sch C-2, Adj. 7, Sh 1	LNG Adj. No. 18 (j) Sch B-2, Adj. 18, Sh 1	Adjusted 1/31/2019 (k) Sum (c)-(j)	Line No.
	Purchased Gas Costs											
1	Natural Gas Transmission Line Purchases	803	$ 116,448,762	$ (116,448,762)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2	Purchased Gas Cost Adjustments	805	77,881,083	(77,881,083)	0	0	0	0	0	0	0	2
3	Gas Withdrawn From Storage	808	226,519	(226,519)	0	0	0	0	0	0	0	3
4	Gas Delivered To Storage	808	(16,523)	16,523	0	0	0	0	0	0	0	4
5	Gas Used for Compressor Station Fuel	810	0	0	0	0	0	0	0	0	0	5
6	Total Purchased Gas Costs	Sum Lns 1-5	$ 194,539,841	$ (194,539,841)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	6
	Other Gas Costs											
	Other Gas Supply	813										
7	Labor		$ 712,806	$ 0	$ 64,852	$ 0	$ 0	$ 0	$ 0	$ 0	$ 777,658	7
8	Labor Loadings		410,306	0	26,065	0	0	0	0	0	436,371	8
9	Materials and Expenses		144,118	0	0	0	0	0	0	0	144,118	9
10	Total Other Gas Supply	Sum Lns 7-9	$ 1,267,230	$ 0	$ 90,917	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,358,147	10
	Storage											
11	LNG Storage Facility	Various	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,470,088	$ 1,470,088	11
	Transmission											
12	Transmission and Compression of Gas by Others	858	$ 6,633,789	$ (6,633,789)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
	Distribution											
	Operation Supervision and Engineering	870										
13	Labor		$ 6,127,213	$ 0	$ 273,694	$ 0	$ 0	$ 0	$ 0	$ 0	$ 6,400,906	13
14	Labor Loadings		3,545,881	0	61,450	0	0	0	0	0	3,607,331	14
15	Materials and Expenses		1,638,998	0	0	0	(233,734)	42,775	0	0	1,448,039	15
16	Total Operation Supervision and Engineering	Sum Lns 13-15	$ 11,312,091	$ 0	$ 335,144	$ 0	$ (233,734)	$ 42,775	$ 0	$ 0	$ 11,456,277	16
	Operation Distribution Load Dispatching	871										
17	Labor		$ 301,833	$ 0	$ 29,631	$ 0	$ 0	$ 0	$ 0	$ 0	$ 331,464	17
18	Labor Loadings		174,155	0	12,463	0	0	0	0	0	186,619	18
19	Materials and Expenses		157,480	0	0	0	0	0	0	0	157,480	19
20	Total Operation Distribution Load Dispatching	Sum Lns 17-19	$ 633,468	$ 0	$ 42,095	$ 0	$ 0	$ 0	$ 0	$ 0	$ 675,562	20
	Operation Mains and Services	874										
21	Labor		$ 2,839,961	$ 0	$ 127,659	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,967,620	21
22	Labor Loadings		1,633,746	0	27,929	0	0	0	0	0	1,661,675	22
23	Materials and Expenses		7,944,516	0	0	0	(230)	0	0	0	7,944,286	23
24	Total Operation Mains and Services	Sum Lns 21-23	$ 12,418,223	$ 0	$ 155,588	$ 0	$ (230)	$ 0	$ 0	$ 0	$ 12,573,581	24
	Operation Measuring and Regulation Station	875										
25	Labor		$ 1,102,167	$ 0	$ 49,406	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,151,572	25
26	Labor Loadings		644,057	0	10,978	0	0	0	0	0	655,035	26
27	Materials and Expenses		698,517	0	0	0	0	0	0	0	698,517	27
28	Total Operation Measuring and Regulation Station	Sum Lns 25-27	$ 2,444,742	$ 0	$ 60,383	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,505,125	28
	Operation Meter and House Regulator	878										
29	Labor		$ 4,652,731	$ 0	$ 209,014	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,861,745	29
30	Labor Loadings		2,659,080	0	45,423	0	0	0	0	0	2,704,502	30
31	Materials and Expenses		3,177,057	0	0	0	0	0	0	0	3,177,057	31
32	Total Operation Meter and House Regulator	Sum Lns 29-31	$ 10,488,868	$ 0	$ 254,436	$ 0	$ 0	$ 0	$ 0	$ 0	$ 10,743,304	32

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATIONS AND MAINTENANCE EXPENSE AS ADJUSTED
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description (a)	Account No. (b)	Recorded 1/31/2019 (c)	Purchased Gas Cost Adj. No. 2 (d)	Labor/Loading Annualization Adj. No. 3 (e)	Call Center & Customer Supp. Adj. No. 4 (f)	Cost of Service Analysis Adj. No. 5 (g)	Employee Vehicles Adj. No. 6 (h)	Uncollectibles Annualization Adj. No. 7 (i)	LNG Adj. No. 18 (j)	Adjusted 1/31/2019 (k)	Line No.
					Sch C-2, Adj. 3, Sh 1, Cols (b)-(c)	Sch C-2, Adj. 4, Sh 1	Sch C-2, Adj. 5, Sh 1 Sch C-2, Adj. 5, Sh 2	Sch C-2, Adj. 6, Sh 2	Sch C-2, Adj. 7, Sh 1	Sch B-2, Adj. 18, Sh 1	Sum (c)-(j)	
	Customer Installation	879										
1	Labor		$ 6,509,746	$ 0	$ 357,141	$ 0	$ 0	$ 0	$ 0	$ 0	$ 6,866,887	1
2	Labor Loadings		3,714,474	0	101,285	0	0	0	0	0	3,815,759	2
3	Materials and Expenses		1,798,117	0	0	0	0	0	0	0	1,798,117	3
4	Total Customer Installation	Sum Lns 1-3	$ 12,022,337	$ 0	$ 458,427	$ 0	$ 0	$ 0	$ 0	$ 0	$ 12,480,763	4
	Other	880										
5	Labor		$ 3,961,719	$ 0	$ 207,052	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,168,772	5
6	Labor Loadings		2,316,560	0	56,903	0	0	0	0	0	2,373,463	6
7	Materials and Expenses		6,690,084	0	0	0	(98,962)	0	0	0	6,591,122	7
8	Total Other	Sum Lns 5-7	$ 12,968,364	$ 0	$ 263,955	$ 0	$ (98,962)	$ 0	$ 0	$ 0	$ 13,133,357	8
9	Rents	881	$ (634,635)	$ 0	$ 0	$ 0	$ (89,800)	$ 0	$ 0	$ 0	$ (724,435)	9
	Maintenance Supervision and Engineering	885										
10	Labor		$ 1,385,693	$ 0	$ 62,278	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,447,971	10
11	Labor Loadings		796,816	0	13,698	0	0	0	0	0	810,514	11
12	Materials and Expenses		269,887	0	0	0	(4,888)	0	0	0	264,999	12
13	Total Maintenance Supervision and Engineering	Sum Lns 10-12	$ 2,452,396	$ 0	$ 75,976	$ 0	$ (4,888)	$ 0	$ 0	$ 0	$ 2,523,484	13
	Maintenance of Structures and Improvements	886										
14	Labor		$ 15,621	$ 0	$ 465	$ 0	$ 0	$ 0	$ 0	$ 0	$ 16,085	14
15	Labor Loadings		9,619	0	108	0	0	0	0	0	9,727	15
16	Materials and Expenses		53,126	0	0	0	0	0	0	0	53,126	16
17	Total Maintenance of Structures and Improvements	Sum Lns 14-16	$ 78,366	$ 0	$ 573	$ 0	$ 0	$ 0	$ 0	$ 0	$ 78,938	17
	Maintenance of Mains	887										
18	Labor		$ 7,060,051	$ 0	$ 317,150	$ 0	$ 0	$ 0	$ 0	$ 0	$ 7,377,201	18
19	Labor Loadings		4,102,278	0	70,076	0	0	0	0	0	4,172,353	19
20	Materials and Expenses		12,649,372	0	0	0	(840)	0	0	0	12,648,532	20
21	Total Maintenance of Mains	Sum Lns 18-20	$ 23,811,700	$ 0	$ 387,226	$ 0	$ (840)	$ 0	$ 0	$ 0	$ 24,198,086	21
	Maintenance of Measuring and Reg. Station Eq.	889										
22	Labor		$ 1,128,474	$ 0	$ 50,693	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,179,167	22
23	Labor Loadings		652,882	0	11,153	0	0	0	0	0	664,034	23
24	Materials and Expenses		733,457	0	0	0	0	0	0	0	733,457	24
25	Total Maintenance of Measuring and Reg. Station Eq.	Sum Lns 22-24	$ 2,514,812	$ 0	$ 61,846	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,576,658	25
	Maintenance of Services	892										
26	Labor		$ 3,548,600	$ 0	$ 159,533	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,708,133	26
27	Labor Loadings		2,073,986	0	35,458	0	0	0	0	0	2,109,444	27
28	Materials and Expenses		7,070,213	0	0	0	0	0	0	0	7,070,213	28
29	Total Maintenance of Services	Sum Lns 26-28	$ 12,692,799	$ 0	$ 194,991	$ 0	$ 0	$ 0	$ 0	$ 0	$ 12,887,790	29

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATIONS AND MAINTENANCE EXPENSE AS ADJUSTED
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description (a)	Account No. (b)	Recorded 1/31/2019 (c)	Purchased Gas Cost Adj. No. 2 (d)	Labor/Loading Annualization Adj. No. 3 (e) Sch C-2, Adj. 3, Sh 1, Cols (b)-(c)	Call Center & Customer Supp. Adj. No. 4 (f) Sch C-2, Adj. 4, Sh 1	Cost of Service Analysis Adj. No. 5 (g) Sch C-2, Adj. 5, Sh 1 Sch C-2, Adj. 5, Sh 2	Employee Vehicles Adj. No. 6 (h) Sch C-2, Adj. 6, Sh 2	Uncollectibles Annualization Adj. No. 7 (i) Sch C-2, Adj. 7, Sh 1	LNG Adj. No. 18 (j) Sch B-2, Adj. 18, Sh 1	Adjusted 1/31/2019 (k) Sum (c)-(j)	Line No.
	Maintenance of Meters and House Regulators	893										
1	Labor		$ 1,496,660	$ 0	$ 67,244	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,563,904	1
2	Labor Loadings		851,232	0	14,543	0	0	0	0	0	865,775	2
3	Materials and Expenses		1,063,225	0	0	0	0	0	0	0	1,063,225	3
4	Total Maintenance of Meters and House Regulators	Sum Lns 1-3	$ 3,411,116	$ 0	$ 81,788	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,492,904	4
	Maintenance of Other Equipment	894										
5	Labor		$ 175,906	$ 0	$ 7,905	$ 0	$ 0	$ 0	$ 0	$ 0	$ 183,812	5
6	Labor Loadings		101,773	0	1,739	0	0	0	0	0	103,512	6
7	Materials and Expenses		73,309	0	0	0	0	0	0	0	73,309	7
8	Total Maintenance of Other Equipment	Sum Lns 5-7	$ 350,988	$ 0	$ 9,645	$ 0	$ 0	$ 0	$ 0	$ 0	$ 360,633	8
	Total Distribution											
9	Labor		$ 40,306,374	$ 0	$ 1,918,865	$ 0	$ 0	$ 0	$ 0	$ 0	$ 42,225,239	9
10	Labor Loadings		23,276,538	0	463,206	0	0	0	0	0	23,739,744	10
11	Materials and Expenses		43,382,724	0	0	0	(428,454)	42,775	0	0	42,997,045	11
12	Total Distribution	Sum Lns 9-11	$ 106,965,636	$ 0	$ 2,382,071	$ 0	$ (428,454)	$ 42,775	$ 0	$ 0	$ 108,962,028	12
	Customer Accounts											
	Supervision	901										
13	Labor		$ 931,175	$ 0	$ 82,618	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,013,793	13
14	Labor Loadings		533,305	0	33,046	0	0	0	0	0	566,351	14
15	Materials and Expenses		263,555	0	0	0	(739)	0	0	0	262,816	15
16	Total Supervision	Sum Lns 13-15	$ 1,728,035	$ 0	$ 115,664	$ 0	$ (739)	$ 0	$ 0	$ 0	$ 1,842,960	16
	Meter Reading	902										
17	Labor		$ 754,888	$ 0	$ 33,765	$ 0	$ 0	$ 0	$ 0	$ 0	$ 788,653	17
18	Labor Loadings		436,928	0	7,429	0	0	0	0	0	444,357	18
19	Materials and Expenses		324,290	0	0	0	0	0	0	0	324,290	19
20	Total Meter Reading	Sum Lns 17-19	$ 1,516,106	$ 0	$ 41,194	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,557,300	20
	Customer Records and Collection	903										
21	Labor		$ 4,530,484	$ 0	$ 474,495	$ 0	$ 0	$ 0	$ 0	$ 0	$ 5,004,978	21
22	Labor Loadings		2,617,987	0	208,294	0	0	0	0	0	2,826,281	22
23	Materials and Expenses		12,922,401	0	0	73,158	(51,008)	0	0	0	12,944,550	23
24	Total Customer Records and Collection	Sum Lns 21-23	$ 20,070,871	$ 0	$ 682,789	$ 73,158	$ (51,008)	$ 0	$ 0	$ 0	$ 20,775,809	24
25	Uncollectible Accounts	904	$ 1,431,902	$ 0	$ 0	$ 0	$ 0	$ 0	$ (81,178)	$ 0	$ 1,350,724	25
	Miscellaneous	905										
26	Labor		$ 72,703	$ 0	$ 3,272	$ 0	$ 0	$ 0	$ 0	$ 0	$ 75,975	26
27	Labor Loadings		43,337	0	742	0	0	0	0	0	44,079	27
28	Materials and Expenses		1,641	0	0	0	0	0	0	0	1,641	28
29	Total Miscellaneous	Sum Lns 26-28	$ 117,681	$ 0	$ 4,014	$ 0	$ 0	$ 0	$ 0	$ 0	$ 121,695	29
	Total Customer Accounts											
30	Labor		$ 6,289,250	$ 0	$ 594,150	$ 0	$ 0	$ 0	$ 0	$ 0	$ 6,883,400	30
31	Labor Loadings		3,631,557	0	249,511	0	0	0	0	0	3,881,068	31
32	Materials and Expenses		14,943,788	0	0	73,158	(51,747)	0	(81,178)	0	14,884,021	32
33	Total Customer Accounts	Sum Lns 30-32	$ 24,864,595	$ 0	$ 843,661	$ 73,158	$ (51,747)	$ 0	$ (81,178)	$ 0	$ 25,648,489	33

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATIONS AND MAINTENANCE EXPENSE AS ADJUSTED
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Account No.	Recorded 1/31/2019	Purchased Gas Cost Adj. No. 2	Labor/Loading Annualization Adj. No. 3	Call Center & Customer Supp. Adj. No. 4	Cost of Service Analysis Adj. No. 5	Employee Vehicles Adj. No. 6	Uncollectibles Annualization Adj. No. 7	LNG Adj. No. 18	Adjusted 1/31/2019	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
					Sch C-2, Adj. 3, Sh 1, Cols (b)-(c)	Sch C-2, Adj. 4, Sh 1	Sch C-2, Adj. 5, Sh 1 Sch C-2, Adj. 5, Sh 2	Sch C-2, Adj. 6, Sh 2	Sch C-2, Adj. 7, Sh 1	Sch B-2, Adj. 18, Sh 1	Sum (c)-(j)	
	Customer Service and Information											
	Customer Assistance	908										
1	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2	Labor Loadings		0	0	0	0	0	0	0	0	0	2
3	Materials and Expenses		24,142	0	0	0	(24,163)	0	0	0	(21)	3
4	Total Customer Assistance	Sum Lns 1-3	$ 24,142	$ 0	$ 0	$ 0	$ (24,163)	$ 0	$ 0	$ 0	$ (21)	4
	Informational and Instructional Advertising	909										
5	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	5
6	Labor Loadings		0	0	0	0	0	0	0	0	0	6
7	Materials and Expenses		0	0	0	0	0	0	0	0	0	7
8	Total Informational and Instructional Advertising	Sum Lns 5-7	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	8
	Miscellaneous	910										
9	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	9
10	Labor Loadings		0	0	0	0	0	0	0	0	0	10
11	Materials and Expenses		400,631	0	0	0	(21,243)	0	0	0	379,388	11
12	Total Miscellaneous	Sum Lns 9-11	$ 400,631	$ 0	$ 0	$ 0	$ (21,243)	$ 0	$ 0	$ 0	$ 379,388	12
	Total Customer Service and Information											
13	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	13
14	Labor Loadings		0	0	0	0	0	0	0	0	0	14
15	Materials and Expenses		424,773	0	0	0	(45,406)	0	0	0	379,366	15
16	Total Customer Service and Information	Sum Lns 13-15	$ 424,773	$ 0	$ 0	$ 0	$ (45,406)	$ 0	$ 0	$ 0	$ 379,366	16
	Sales											
	Supervision	911										
17	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	17
18	Labor Loadings		0	0	0	0	0	0	0	0	0	18
19	Materials and Expenses		0	0	0	0	0	0	0	0	0	19
20	Total Supervision	Sum Lns 17-19	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	20
	Demonstration and Selling	912										
21	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	21
22	Labor Loadings		0	0	0	0	0	0	0	0	0	22
23	Materials and Expenses		0	0	0	0	0	0	0	0	0	23
24	Total Demonstration and Selling	Sum Lns 21-23	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	24
	Advertising	913										
25	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Labor Loadings		0	0	0	0	0	0	0	0	0	26
27	Materials and Expenses		12,629	0	0	0	(5,050)	0	0	0	7,579	27
28	Total Advertising	Sum Lns 25-27	$ 12,629	$ 0	$ 0	$ 0	$ (5,050)	$ 0	$ 0	$ 0	$ 7,579	28
	Total Sales											
29	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	29
30	Labor Loadings		0	0	0	0	0	0	0	0	0	30
31	Materials and Expenses		12,629	0	0	0	(5,050)	0	0	0	7,579	31
32	Total Sales	Sum Lns 29-31	$ 12,629	$ 0	$ 0	$ 0	$ (5,050)	$ 0	$ 0	$ 0	$ 7,579	32
	Total O&M											
33	Labor		$ 47,308,430	$ 0	$ 2,577,866	$ 0	$ 0	$ 0	$ 0	$ 0	$ 49,886,297	33
34	Labor Loadings		27,318,401	0	738,782	0	0	0	0	0	28,057,183	34
35	Materials and Expenses		260,081,662	(201,173,630)	0	73,158	(530,658)	42,775	(81,178)	1,470,088	59,882,217	35
36	Total O&M	Sum Lns 33-35	$ 334,708,493	$ (201,173,630)	$ 3,316,648	$ 73,158	$ (530,658)	$ 42,775	$ (81,178)	$ 1,470,088	$ 137,825,696	36
			Sch C-1, Sh 3, Col (c)								Sch C-1, Sh 3, Col (e)	

SOUTHWEST GAS CORPORATION
ARIZONA
RECORDED ADMINISTRATIVE AND GENERAL (A&G) EXPENSES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Account No./ Reference	Total Company	Direct Charges: Total AZ	Direct Charges: Other Jurisdictions	To Be Allocated to AZ	AZ Allocation Factors: 4-Factor	AZ Allocation Factors: Factor II	AZ Allocation Factors: Factor III	AZ Allocation Factors: A&G Factor	Total Allocation to AZ	Total AZ	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
			Company Records	Company Records	(c) - (d) - (f)	Company Records	55.68% Sch C-1, Sh 17, Ln 9(c)	56.16% Sch C-1, Sh 17, Ln 4(c)	55.70% Sch C-1, Sh 17, Ln 6(c)	63.41% Sch C-1, Sh 17, Ln 10(c)	Sum (g)-(j)	(d) + (k)	
	Administrative and General (A&G)												
	A&G Salaries	920											
1	Labor		$ 62,067,932	$ 0	$ 0	$ 62,067,932	$ 34,557,994	$ 0	$ 0	$ 0	$ 34,557,994	$ 34,557,994	1
2	Labor Loadings		27,924,040	0	0	27,924,040	15,547,462	0	0	0	15,547,462	15,547,462	2
3	Materials and Expenses		(3,689,319)	0	0	(3,689,319)	(2,054,128)	0	0	0	(2,054,128)	(2,054,128)	3
4	Total A&G Salaries	Sum Lns 1-3	$ 86,302,652	$ 0	$ 0	$ 86,302,652	$ 48,051,328	$ 0	$ 0	$ 0	$ 48,051,328	$ 48,051,328	4
5	Office Supplies and Expenses	921	$ 15,930,848	$ 0	$ 0	$ 15,930,848	$ 8,869,929	$ 0	$ 0	$ 0	$ 8,869,929	$ 8,869,929	5
6	A&G Expenses Transferred (Credit)	922	$ (12,965,038)	$ 0	$ 0	$ (12,965,038)	$ 0	$ 0	$ 0	$ (8,221,169)	$ (8,221,169)	$ (8,221,169)	6
7	Outside Services	923	$ 26,475,336	$ 59,291	$ 66,399	$ 26,349,646	$ 14,670,876	$ 0	$ 0	$ 0	$ 14,670,876	$ 14,730,167	7
8	Property Insurance	924	$ 438,203	$ 0	$ 0	$ 438,203	$ 0	$ 246,112	$ 0	$ 0	$ 246,112	$ 246,112	8
9	Injuries and Damages	925	$ 8,057,022	$ 930,895	$ (4,480,303)	$ 11,606,430	$ 6,462,193	$ 0	$ 0	$ 0	$ 6,462,193	$ 7,393,088	9
10	Employee Pension and Benefits	926	$ 19,743,389	$ 32,800	$ 18,685	$ 19,691,904	$ 10,963,998	$ 0	$ 0	$ 0	$ 10,963,998	$ 10,996,799	10
11	Regulatory Commission Expenses	928	$ 121,093	$ 86,892	$ 34,201	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 86,892	11
12	Safety Advertising	930.1	$ 1,791,911	$ 960,146	$ 828,315	$ 3,450	$ 1,921	$ 0	$ 0	$ 0	$ 1,921	$ 962,067	12
	Miscellaneous General	930.2											
13	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	13
14	Labor Loadings		0	0	0	0	0	0	0	0	0	0	14
15	Materials and Expenses		7,688,321	851,062	618,938	6,218,321	3,462,218	0	0	0	3,462,218	4,313,280	15
16	Total Miscellaneous General	Sum Lns 13-15	$ 7,688,321	$ 851,062	$ 618,938	$ 6,218,321	$ 3,462,218	$ 0	$ 0	$ 0	$ 3,462,218	$ 4,313,280	16
17	Rents	931	$ 3,395,785	$ 0	$ 3,738	$ 3,392,047	$ 1,888,613	$ 0	$ 0	$ 0	$ 1,888,613	$ 1,888,613	17
	Maintenance of General Plant	935											
18	Labor		$ 1,093,171	$ 245,202	$ 36,221	$ 811,748	$ 451,963	$ 0	$ 0	$ 0	$ 451,963	$ 697,165	18
19	Labor Loadings		632,878	148,781	21,467	462,630	257,582	0	0	0	257,582	406,363	19
20	Materials and Expenses		4,586,985	1,837,699	506,605	2,242,681	1,248,673	0	0	0	1,248,673	3,086,373	20
21	Total Maint. of General Plant	Sum Lns 18-20	$ 6,313,034	$ 2,231,682	$ 564,292	$ 3,517,060	$ 1,958,218	$ 0	$ 0	$ 0	$ 1,958,218	$ 4,189,900	21
	Total A&G Expenses												
22	Labor		$ 63,161,102	$ 245,202	$ 36,221	$ 62,879,680	$ 35,009,957	$ 0	$ 0	$ 0	$ 35,009,957	$ 35,255,158	22
23	Labor Loadings		28,556,918	148,781	21,467	28,386,670	15,805,044	0	0	0	15,805,044	15,953,825	23
24	Materials and Expenses		71,574,536	4,758,786	(2,403,423)	69,219,173	45,514,293	246,112	0	(8,221,169)	37,539,236	42,298,022	24
25	Total A&G Expenses	Sum Lns 22-24	$ 163,292,556	$ 5,152,768	$ (2,345,735)	$ 160,485,523	$ 96,329,293	$ 246,112	$ 0	$ (8,221,169)	$ 88,354,236	$ 93,507,005	25
			Sch C-1, Sh 13, Col (c)	Sch C-1, Sh 13, Col (d)	Sch C-1, Sh 13, Col (e)							Sch C-1, Sh 4, Col (c)	

SOUTHWEST GAS CORPORATION
ARIZONA
ADJUSTMENTS TO DIRECT ADMINISTRATIVE AND GENERAL (A&G) EXPENSES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Account No./ Reference	Labor/Loading Annualization Adj. No. 3	Cost of Service Analysis Adj. No. 5	Self-Insured Retention Adj. No. 9	Rate Case Expense Adj. No. 12	Total AZ	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
			Sch C-2, Adj. 3, Sh 1, Ln 36	Sch C-2, Adj. 5, Sh 1 Lns 12-13	Sch C-2, Adj. 9, Sh 1, Ln 1(d)	Sch C-2, Adj. 12, Sh 1, Ln 10(c)	Sum (c)-(f)	
	Administrative and General (A&G)							
	A&G Salaries	920						
1	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	1
2	Labor Loadings		0	0	0	0	0	2
3	Materials and Expenses		0	0	0	0	0	3
4	Total A&G Salaries	Sum Lns 1-3	$ 0	$ 0	$ 0	$ 0	$ 0	4
5	Office Supplies and Expenses	921	$ 0	$ 0	$ 0	$ 0	$ 0	5
6	A&G Expenses Transferred (Credit)	922	$ 0	$ 0	$ 0	$ 0	$ 0	6
7	Outside Services	923	$ 0	$ 0	$ 0	$ 0	$ 0	7
8	Property Insurance	924	$ 0	$ 0	$ 0	$ 0	$ 0	8
9	Injuries and Damages	925	$ 0	$ 0	$ 790,608	$ 0	$ 790,608	9
10	Employee Pension and Benefits	926	$ 0	$ 0	$ 0	$ 0	$ 0	10
11	Regulatory Commission Expenses	928	$ 0	$ 0	$ 0	$ 70,108	$ 70,108	11
12	Safety Advertising	930.1	$ 0	$ 0	$ 0	$ 0	$ 0	12
	Miscellaneous General	930.2						
13	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	13
14	Labor Loadings		0	0	0	0	0	14
15	Materials and Expenses		0	(904)	0	0	(904)	15
16	Total Miscellaneous General	Sum Lns 13-15	$ 0	$ (904)	$ 0	$ 0	$ (904)	16
17	Rents	931	$ 0	$ 0	$ 0	$ 0	$ 0	17
	Maintenance of General Plant	935						
18	Labor		$ 12,635	$ 0	$ 0	$ 0	$ 12,635	18
19	Labor Loadings		3,557	0	0	0	3,557	19
20	Materials and Expenses		0	(1,557)	0	0	(1,557)	20
21	Total Maint. of General Plant	Sum Lns 18-20	$ 16,191	$ (1,557)	$ 0	$ 0	$ 14,635	21
	Total A&G Expenses							
22	Labor		$ 12,635	$ 0	$ 0	$ 0	$ 12,635	22
23	Labor Loadings		3,557	0	0	0	3,557	23
24	Materials and Expenses		0	(2,460)	790,608	70,108	858,256	24
25	Total A&G Expenses	Sum Lns 22-24	$ 16,191	$ (2,460)	$ 790,608	$ 70,108	$ 874,447	25
							Sch C-1, Sh 12, Col (d)	

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
ADJUSTMENTS TO ADMINISTRATIVE AND GENERAL (A&G) EXPENSES BEFORE ALLOCATION
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Account No./ Reference	Labor/Loading Annualization Adj. No. 3	Cost of Service Analysis Adj. No. 5	Employee Vehicles Adj. No. 6	Self-Insured Retention Adj. No. 9	AGA Dues Adj. No. 10	Paiute Alloc. Annualization Adj. No. 11	Total System Alloc.	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
			Sch C-2, Adj. 3, Sh 1 Sch C-2, Adj. 3, Sh 2	Sch C-2, Adj. 5, Sh 2, Col (o)	Sch C-2, Adj. 6, Sh 2, Ln 4(e)	Sch C-2, Adj. 9, Sh 1, Ln 4(d)	Sch C-2, Adj. 10, Sh 1, Ln 5(d)	Sch C-2, Adj. 11, Sh 1, Col (h)	Sum (c)-(h)	
	Administrative and General (A&G)									
	A&G Salaries	920								
1	Labor		$ 1,769,671	$ (327,743)	$ 517,678	$ 0	$ 0	$ 0	$ 1,959,606	1
2	Labor Loadings		1,148,216	0	0	0	0	0	1,148,216	2
3	Materials and Expenses		0	0	0	0	0	(217,563)	(217,563)	3
4	Total A&G Salaries	Sum Lns 1-3	$ 2,917,887	$ (327,743)	$ 517,678	$ 0	$ 0	$ (217,563)	$ 2,890,260	4
5	Office Supplies and Expenses	921	$ 0	$ (357,868)	$ 0	$ 0	$ 0	$ (29,847)	$ (387,715)	5
6	A&G Expenses Transferred (Credit)	922	$ (379,325)	$ 0	$ 0	$ 0	$ 0	$ 24,291	$ (355,035)	6
7	Outside Services	923	$ 0	$ (358,328)	$ 0	$ 0	$ 0	$ (13,673)	$ (372,001)	7
8	Property Insurance	924	$ 0	$ 0	$ 0	$ 0	$ 0	$ 5,100	$ 5,100	8
9	Injuries and Damages	925	$ 0	$ 0	$ 0	$ (428,898)	$ 0	$ (5,852)	$ (434,749)	9
10	Employee Pension and Benefits	926	$ (2,037,442)	$ 0	$ 0	$ 0	$ 0	$ 0	$ (2,037,442)	10
11	Regulatory Commission Expenses	928	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	11
12	Safety Advertising	930.1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
	Miscellaneous General	930.2								
13	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	13
14	Labor Loadings		0	0	0	0	0	0	0	14
15	Materials and Expenses		0	(2,850)	0	0	(21,572)	(277,916)	(302,338)	15
16	Total Miscellaneous General	Sum Lns 13-15	$ 0	$ (2,850)	$ 0	$ 0	$ (21,572)	$ (277,916)	$ (302,338)	16
17	Rents	931	$ 0	$ (24,408)	$ 0	$ 0	$ 0	$ (6,147)	$ (30,555)	17
	Maintenance of General Plant	935								
18	Labor		$ 29,736	$ 0	$ 0	$ 0	$ 0	$ 0	$ 29,736	18
19	Labor Loadings		19,074	0	0	0	0	0	19,074	19
20	Materials and Expenses		0	0	0	0	0	(3,285)	(3,285)	20
21	Total Maint. of General Plant	Sum Lns 18-20	$ 48,810	$ 0	$ 0	$ 0	$ 0	$ (3,285)	$ 45,525	21
	Total A&G Expenses									
22	Labor		$ 1,799,407	$ (327,743)	$ 517,678	$ 0	$ 0	$ 0	$ 1,989,342	22
23	Labor Loadings		1,167,291	0	0	0	0	0	1,167,291	23
24	Materials and Expenses		(2,416,767)	(743,454)	0	(428,898)	(21,572)	(524,892)	(4,135,582)	24
25	Total A&G Expenses	Sum Lns 22-24	$ 549,931	$ (1,071,197)	$ 517,678	$ (428,898)	$ (21,572)	$ (524,892)	$ (978,949)	25
									Sch C-1, Sh 12, Col (f)	

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF ADMINISTRATIVE AND GENERAL (A&G) EXPENSE ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Account No./ Reference	Total Company	Direct Charges: Total AZ	Direct Charges: Other Jurisdictions	To Be Allocated to AZ	AZ Allocation Factors: 4-Factor	AZ Allocation Factors: Factor II	AZ Allocation Factors: Factor III	AZ Allocation Factors: A&G Factor	Total Allocation to AZ	Total AZ	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
			(d) + (e) + (f)	Sch C-1, Sh 10, Col (g)	N/A	Sch C-1, Sh 11, Col (i)	55.68% Sch C-1, Sh 17, Ln 9(c)	56.16% Sch C-1, Sh 17, Ln 4(c)	55.70% Sch C-1, Sh 17, Ln 6(c)	63.41% Sch C-1, Sh 17, Ln 10(c)	Sum (g)-(j)	(d) + (k)	
	Administrative and General (A&G)												
	A&G Salaries	920											
1	Labor		$ 1,959,606	$ 0	$ 0	$ 1,959,606	$ 1,091,063	$ 0	$ 0	$ 0	$ 1,091,063	$ 1,091,063	1
2	Labor Loadings		1,148,216	0	0	1,148,216	639,300	0	0	0	639,300	639,300	2
3	Materials and Expenses		(217,563)	0	0	(217,563)	(121,134)	0	0	0	(121,134)	(121,134)	3
4	Total A&G Salaries	Sum Lns 1-3	$ 2,890,260	$ 0	$ 0	$ 2,890,260	$ 1,609,230	$ 0	$ 0	$ 0	$ 1,609,230	$ 1,609,230	4
5	Office Supplies and Expenses	921	$ (387,715)	$ 0	$ 0	$ (387,715)	$ (215,871)	$ 0	$ 0	$ 0	$ (215,871)	$ (215,871)	5
6	A&G Expenses Transferred (Credit)	922	$ (355,035)	$ 0	$ 0	$ (355,035)	$ 0	$ 0	$ 0	$ (225,129)	$ (225,129)	$ (225,129)	6
7	Outside Services	923	$ (372,001)	$ 0	$ 0	$ (372,001)	$ (207,121)	$ 0	$ 0	$ 0	$ (207,121)	$ (207,121)	7
8	Property Insurance	924	$ 5,100	$ 0	$ 0	$ 5,100	$ 0	$ 2,865	$ 0	$ 0	$ 2,865	$ 2,865	8
9	Injuries and Damages	925	$ 355,859	$ 790,608	$ 0	$ (434,749)	$ (242,058)	$ 0	$ 0	$ 0	$ (242,058)	$ 548,550	9
10	Employee Pension and Benefits	926	$ (2,037,442)	$ 0	$ 0	$ (2,037,442)	$ (1,134,401)	$ 0	$ 0	$ 0	$ (1,134,401)	$ (1,134,401)	10
11	Regulatory Commission Expenses	928	$ 70,108	$ 70,108	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 70,108	11
12	Safety Advertising	930.1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
	Miscellaneous General	930.2											
13	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	13
14	Labor Loadings		0	0	0	0	0	0	0	0	0	0	14
15	Materials and Expenses		(303,242)	(904)	0	(302,338)	(168,335)	0	0	0	(168,335)	(169,239)	15
16	Total Miscellaneous General	Sum Lns 13-15	$ (303,242)	$ (904)	$ 0	$ (302,338)	$ (168,335)	$ 0	$ 0	$ 0	$ (168,335)	$ (169,239)	16
17	Rents	931	$ (30,555)	$ 0	$ 0	$ (30,555)	$ (17,012)	$ 0	$ 0	$ 0	$ (17,012)	$ (17,012)	17
	Maintenance of General Plant	935											
18	Labor		$ 42,370	$ 12,635	$ 0	$ 29,736	$ 16,556	$ 0	$ 0	$ 0	$ 16,556	$ 29,191	18
19	Labor Loadings		22,631	3,557	0	19,074	10,620	0	0	0	10,620	14,177	19
20	Materials and Expenses		(4,842)	(1,557)	0	(3,285)	(1,829)	0	0	0	(1,829)	(3,386)	20
21	Total Maint. of General Plant	Sum Lns 18-20	$ 60,160	$ 14,635	$ 0	$ 45,525	$ 25,347	$ 0	$ 0	$ 0	$ 25,347	$ 39,982	21
	Total A&G Expenses												
22	Labor		$ 2,001,976	$ 12,635	$ 0	$ 1,989,342	$ 1,107,620	$ 0	$ 0	$ 0	$ 1,107,620	$ 1,120,254	22
23	Labor Loadings		1,170,847	3,557	0	1,167,291	649,921	0	0	0	649,921	653,477	23
24	Materials and Expenses		(3,277,326)	858,256	0	(4,135,582)	(2,107,761)	2,865	0	(225,129)	(2,330,025)	(1,471,770)	24
25	Total A&G Expenses	Sum Lns 22-24	$ (104,502)	$ 874,447	$ 0	$ (978,949)	$ (350,221)	$ 2,865	$ 0	$ (225,129)	$ (572,485)	$ 301,962	25
			Sch C-1, Sh 13, Col (c)	Sch C-1, Sh 13, Col (d)	Sch C-1, Sh 13, Col (e)							Sch C-1, Sh 4 Col (d)	

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF ADJUSTED ADMINISTRATIVE AND GENERAL (A&G) EXPENSES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Account No./ Reference	Total Company	Direct Charges: Total AZ	Direct Charges: Other Jurisdictions	To Be Allocated to AZ	AZ Allocation Factors: 4-Factor	AZ Allocation Factors: Factor II	AZ Allocation Factors: Factor III	AZ Allocation Factors: A&G Factor	Total Allocation to AZ	Total AZ	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
			Sch C-1, Sh 9, Col (c) Sch C-1, Sh 12, Col (c)	Sch C-1, Sh 9, Col (d) Sch C-1, Sh 12, Col (d)	Sch C-1, Sh 9, Col (e) Sch C-1, Sh 12, Col (e)	(c) - (d) - (e)	55.68% Sch C-1, Sh 17, Ln 9(c)	56.16% Sch C-1, Sh 17, Ln 4(c)	55.70% Sch C-1, Sh 17, Ln 6(c)	63.41% Sch C-1, Sh 17, Ln 10(c)	Sum (g)-(j)	(d) + (k)	
	Administrative and General (A&G)												
	A&G Salaries	920											
1	Labor		$ 64,027,537	$ 0	$ 0	$ 64,027,537	$ 35,649,057	$ 0	$ 0	$ 0	$ 35,649,057	$ 35,649,057	1
2	Labor Loadings		29,072,256	0	0	29,072,256	16,186,762	0	0	0	16,186,762	16,186,762	2
3	Materials and Expenses		(3,906,882)	0	0	(3,906,882)	(2,175,262)	0	0	0	(2,175,262)	(2,175,262)	3
4	Total A&G Salaries	Sum Lns 1-3	$ 89,192,912	$ 0	$ 0	$ 89,192,912	$ 49,660,558	$ 0	$ 0	$ 0	$ 49,660,558	$ 49,660,558	4
5	Office Supplies and Expenses	921	$ 15,543,133	$ 0	$ 0	$ 15,543,133	$ 8,654,058	$ 0	$ 0	$ 0	$ 8,654,058	$ 8,654,058	5
6	A&G Expenses Transferred (Credit)	922	$ (13,320,072)	$ 0	$ 0	$ (13,320,072)	$ 0	$ 0	$ 0	$ (8,446,298)	$ (8,446,298)	$ (8,446,298)	6
7	Outside Services	923	$ 26,103,336	$ 59,291	$ 66,399	$ 25,977,645	$ 14,463,754	$ 0	$ 0	$ 0	$ 14,463,754	$ 14,523,045	7
8	Property Insurance	924	$ 443,303	$ 0	$ 0	$ 443,303	$ 0	$ 248,977	$ 0	$ 0	$ 248,977	$ 248,977	8
9	Injuries and Damages	925	$ 8,412,881	$ 1,721,503	$ (4,480,303)	$ 11,171,681	$ 6,220,134	$ 0	$ 0	$ 0	$ 6,220,134	$ 7,941,638	9
10	Employee Pension and Benefits	926	$ 17,705,947	$ 32,800	$ 18,685	$ 17,654,463	$ 9,829,598	$ 0	$ 0	$ 0	$ 9,829,598	$ 9,862,398	10
11	Regulatory Commission Expenses	928	$ 191,201	$ 157,000	$ 34,201	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 157,000	11
12	Safety Advertising	930.1	$ 1,791,911	$ 960,146	$ 828,315	$ 3,450	$ 1,921	$ 0	$ 0	$ 0	$ 1,921	$ 962,067	12
	Miscellaneous General	930.2											
13	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	13
14	Labor Loadings		0	0	0	0	0	0	0	0	0	0	14
15	Materials and Expenses		7,385,079	850,158	618,938	5,915,983	3,293,883	0	0	0	3,293,883	4,144,041	15
16	Total Miscellaneous General	Sum Lns 13-15	$ 7,385,079	$ 850,158	$ 618,938	$ 5,915,983	$ 3,293,883	$ 0	$ 0	$ 0	$ 3,293,883	$ 4,144,041	16
17	Rents	931	$ 3,365,230	$ 0	$ 3,738	$ 3,361,492	$ 1,871,601	$ 0	$ 0	$ 0	$ 1,871,601	$ 1,871,601	17
	Maintenance of General Plant	935											
18	Labor		$ 1,135,541	$ 257,836	$ 36,221	$ 841,484	$ 468,519	$ 0	$ 0	$ 0	$ 468,519	$ 726,355	18
19	Labor Loadings		655,509	152,338	21,467	481,705	268,202	0	0	0	268,202	420,540	19
20	Materials and Expenses		4,582,143	1,836,143	506,605	2,239,396	1,246,844	0	0	0	1,246,844	3,082,987	20
21	Total Maint. of General Plant	Sum Lns 18-20	$ 6,373,193	$ 2,246,317	$ 564,292	$ 3,562,585	$ 1,983,565	$ 0	$ 0	$ 0	$ 1,983,565	$ 4,229,882	21
	Total A&G Expenses												
22	Labor		$ 65,163,078	$ 257,836	$ 36,221	$ 64,869,022	$ 36,117,576	$ 0	$ 0	$ 0	$ 36,117,576	$ 36,375,413	22
23	Labor Loadings		29,727,765	152,338	21,467	29,553,960	16,454,964	0	0	0	16,454,964	16,607,302	23
24	Materials and Expenses		68,297,210	5,617,041	(2,403,423)	65,083,592	43,406,532	248,977	0	(8,446,298)	35,209,211	40,826,252	24
25	Total A&G Expenses	Sum Lns 22-24	$ 163,188,054	$ 6,027,215	$ (2,345,735)	$ 159,506,574	$ 95,979,072	$ 248,977	$ 0	$ (8,446,298)	$ 87,781,751	$ 93,808,967	25
												Sch C-1, Sh 4, Col (e)	

SOUTHWEST GAS CORPORATION
ARIZONA
DEPRECIATION AND AMORTIZATION EXPENSE SUMMARY
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description	Reference	Acct. No.	Recorded 1/31/2019	Adjustments	Adjusted 1/31/2019	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
					(f) - (d)		
	AZ Direct Depreciation & Amort.			Sch C-2, Adj. 13, Sh 1		Sch C-2, Adj. 13, Sh 1	
1	Depreciation		403	$ 90,461,589	$ 10,835,680	$ 101,297,269	1
2	Amortization		404	80,000	0	80,000	2
3	Total AZ Direct Deprec. & Amort.	Ln 1 + Ln 2		$ 90,541,589	$ 10,835,680	$ 101,377,269	3
	AZ Regulatory Amortizations						
4	Amort. Of Gas Plant Acq.	Sch C-2, Adj. 16, Sh 1	406	$ (52,943)	$ 49,800	$ (3,143)	4
5	Regulatory Amortizations	Sch C-2, Adj. 16, Sh 1	407.3	6,822,585	(10,248,717)	(3,426,132)	5
6	Total AZ Regulatory Amortizations	Ln 4 + Ln 5		$ 6,769,642	$ (10,198,917)	$ (3,429,275)	6
7	Total AZ Depreciation & Amorts.	Ln 3 + Ln 6		$ 97,311,231	$ 636,763	$ 97,947,994	7
	System Allocable			Sch C-2, Adj. 13, Sh 2		Sch C-2, Adj. 13, Sh 2	
8	Depreciation			$ 6,376,178	$ 1,236,300	$ 7,612,478	8
9	Amortization			13,622,814	5,129,809	18,752,623	9
10	Total System Allocable	Ln 8 + Ln 9		$ 19,998,992	$ 6,366,109	$ 26,365,101	10
11	AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)		55.68%	55.68%	55.68%	11
12	Allocation to AZ	Ln 10 * Ln 11		$ 11,134,978	$ 3,544,503	$ 14,679,481	12
13	Total Depreciation and Amortization	Ln 7 + Ln 12		$ 108,446,208	$ 4,181,266	$ 112,627,474	13

SOUTHWEST GAS CORPORATION
ARIZONA
TAXES OTHER THAN INCOME TAXES SUMMARY
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description	Reference	Recorded 1/31/2019	Adjustments	Adjusted 1/31/2019	Line No.
	(a)	(b)	(c)	(d)	(e)	
			Company Records	Sch C-2, Adj. 14, Sh 1	(c) + (d)	
1	Property Taxes	408.1	$ 41,737,847	$ 15,929,637	$ 57,667,484	1
2	Miscellaneous Taxes [1]	408.1	506,501	(18,226)	488,275	2
3	Total Taxes Other than Income	Ln 1 + Ln 2	$ 42,244,348	$ 15,911,411	$ 58,155,759	3
			Sch C-1, Sh 1, Ln 15(c)		Sch C-1, Sh 1, Ln 15(e)	

[1] Allocation of System Allocable Miscellaneous Taxes

Modified Business Tax	Company Records	$ 805,730
AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)	55.68%
Adjustment Allocated to AZ		$ 448,612
		added to Ln 2(c)

SOUTHWEST GAS CORPORATION
ARIZONA
INCOME TAXES ON OPERATIONS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description	Reference	Recorded 1/31/2019	Adjusted 1/31/2019	After Rate Relief	Line No.
	(a)	(b)	(c)	(d)	(e)	
	State Income Tax					
1	Margin	Sch A-1, Sh 2, Ln 3	$ 500,687,809	$ 518,218,363	$ 575,219,806	1
2	Expenses	Sch A-1, Sh 2, Lns 4-16	379,913,302	403,376,330	403,486,349	2
3	Taxable Income Before Interest	Ln 1 - Ln 2	$ 120,774,507	$ 114,842,033	$ 171,733,457	3
4	Interest Expense	Ln 21	42,132,413	47,329,818	47,329,818	4
5	State Taxable Income	Ln 3 - Ln 4	$ 78,642,094	$ 67,512,215	$ 124,403,639	5
6	Effective State Income Tax Rate	Sch C-3, Sh 2, Ln 1	4.900%	4.900%	4.900%	6
7	State Income Tax Expense	Ln 5 * Ln 6	$ 3,853,463	$ 3,308,099	$ 6,095,778	7
	Federal Income Tax					
8	Margin	Ln 1	$ 500,687,809	$ 518,218,363	$ 575,219,806	8
9	Expenses	Ln 2	379,913,302	403,376,330	403,486,349	9
10	Taxable Income Before Interest	Ln 8 - Ln 9	$ 120,774,507	$ 114,842,033	$ 171,733,457	10
11	Interest Expense	Ln 21	42,132,413	47,329,818	47,329,818	11
12	Federal Taxable Income	Ln 10 - Ln 11	$ 78,642,094	$ 67,512,215	$ 124,403,639	12
13	Federal Income Tax Rate	Sch C-3, Sh 2, Ln 3	19.971%	19.971%	19.971%	13
14	Federal Income Tax Expense	Ln 12 * Ln 13	$ 15,705,613	$ 13,482,864	$ 24,844,651	14
15	ARAM Amortization	Sch B-6, Sh 6	0	(15,458,159)	(15,458,159)	15
16	Investment Tax Credit	Company Records	(467,723)	0	0	16
17	Federal Income Tax Expense	Sum Lns 14-16	$ 15,237,890	$ (1,975,294)	$ 9,386,492	17
18	Total Federal and State Income Tax	Ln 7 + Ln 17	$ 19,091,352	$ 1,332,804	$ 15,482,271	18
			Sch A-1, Sh 2 Ln 17(c)	Sch A-1, Sh 2 Ln 17(e)	Sch A-1, Sh 2 Ln 17(g)	
	Interest Calculation					
19	Rate Base	Sch A-1, Sh 2, Ln 34	$ 1,772,846,788	$ 1,991,543,072	$ 2,612,828,261	19
20	Weighted Cost of Debt	Sch D-1, Sh 1	2.38%	2.38%	1.81%	20
21	Interest Expense	Ln 19 * Ln 20	$ 42,132,413	$ 47,329,818	$ 47,329,818	21
			Lns 4 and 11	Lns 4 and 11	Lns 4 and 11	

SOUTHWEST GAS CORPORATION
ARIZONA
COMPUTATION OF 4-FACTOR AND A&G ALLOCATION RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description (a)	Reference (b)	AZ (c)	SCA (d)	NCA (e)	SLT (f)	SNV (g)	NNV (h)	Total (i) Sum (c)-(h)	Line No.
	Factor I									
1	Direct Operating Expenses	Company Records	$ 137,255,730	$ 19,312,811	$ 2,906,286	$ 3,213,364	$ 61,314,837	$ 14,124,723	$ 238,127,751	1
2	Percent of Total	Ln 1 / Ln 1(i)	57.64%	8.11%	1.22%	1.35%	25.75%	5.93%	100.00%	2
	Factor II									
3	Avg Direct Gross Plant in Service	Company Records	$ 3,533,032,235	$ 450,798,901	$ 146,804,871	$ 68,403,713	$ 1,814,150,030	$ 277,373,727	$ 6,290,563,477	3
4	Percent of Total	Ln 3 / Ln 3(i)	56.16%	7.17%	2.33%	1.09%	28.84%	4.41%	100.00%	4
	Factor III									
5	Direct Labor	Company Records	$ 47,553,630	$ 7,916,298	$ 1,073,123	$ 1,255,809	$ 21,493,636	$ 6,085,670	$ 85,378,166	5
6	Percent of Total	Ln 5 / Ln 5(i)	55.70%	9.27%	1.26%	1.47%	25.17%	7.13%	100.00%	6
	Factor IV									
7	Average Number of Customers	Company Records	$ 1,075,077	$ 147,500	$ 27,106	$ 20,037	$ 654,191	$ 96,546	$ 2,020,457	7
8	Percent of Total	Ln 7 / Ln 7(i)	53.21%	7.30%	1.34%	0.99%	32.38%	4.78%	100.00%	8
9	4-Factor	(Ln 2+ Ln 4+ Ln 6 + Ln 8) / 4	**55.68%**	7.96%	1.54%	1.22%	28.04%	5.56%	100.00%	9
	A&G Transfer Rate									
10	SWG A&G Overheads	Company Records	63.41%	4.66%	0.78%	0.97%	28.51%	1.66%	100.00%	10

SOUTHWEST GAS CORPORATION
ARIZONA
COMPUTATION OF THE MODIFIED MASSACHUSETTS FORMULA (MMF)
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description (a)	Reference (b)	AZ (c)	NCA (d)	SCA (e)	SLT (f)	NNV (g)	SNV (h)	Paiute (i)	SGTC (j)	Total (k) Sum (c)-(j)	Line No.
1	Total Direct Labor	Sch C-1, Sh 17, Ln 5	$ 47,553,630	$ 1,073,123	$ 7,916,298	$ 1,255,809	$ 6,085,670	$ 21,493,636	$ 4,230,386	$ 14,183	$ 89,622,736	1
2	Percent of Total	Ln 1 / Ln 1(k)	53.06%	1.20%	8.83%	1.40%	6.79%	23.98%	4.72%	0.02%	100.00%	2
3	Margin	Company Records	$ 500,687,812	$ 20,257,074	$ 74,364,640	$ 10,460,952	$ 44,141,627	$ 247,209,655	$ 43,043,260	$ 425,945	$ 940,590,965	3
4	Percent of Total	Ln 3 / Ln 3(k)	53.23%	2.15%	7.91%	1.11%	4.69%	26.28%	4.58%	0.05%	100.00%	4
5	Gross Plant	Company Records	$ 3,704,575,635	$ 147,697,855	$ 464,296,640	$ 71,047,200	$ 283,142,922	$ 1,874,463,394	$ 280,752,703	$ 2,426,992	$ 6,828,403,341	5
6	Percent of Total	Ln 5 / Ln 5(k)	54.25%	2.16%	6.80%	1.04%	4.15%	27.45%	4.11%	0.04%	100.00%	6
7	MMF	(Ln 2+ Ln 4 + Ln 6) / 3	53.51%	1.84%	7.85%	1.18%	5.21%	25.91%	**4.47%**	**0.03%**	100.00%	7

SOUTHWEST GAS CORPORATION
ARIZONA
ITEMIZATION OF PRO FORMA ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description (a)	Revenues & Volumes Adj. No. 1 (b) Sch C-2, Adj. 1, Sh 1	Purchased Gas Cost Adj. No. 2 (c) Sch C-2, Adj. 2, Sh 1	Labor/Loading Annualization Adj. No. 3 (d) Sch C-2, Adj. 3, Sh 1 Sch C-2, Adj. 3, Sh 2	Call Center & Customer Supp. Adj. No. 4 (e) Sch C-2, Adj. 4, Sh 1	Cost of Service Analysis Adj. No. 5 (f) Sch C-2, Adj. 5, Sh 1 Sch C-2, Adj. 5, Sh 2	Employee Vehicles Adj. No. 6 (g) Sch C-2, Adj. 6, Sh 1 Sch C-2, Adj. 6, Sh 2	Uncollectibles Annualization Adj. No. 7 (h) Sch C-2, Adj. 7, Sh 1	Self-Insured Retention Adj. No. 9 (i) Sch C-2, Adj. 9, Sh 1	AGA Dues Adj. No. 10 (j) Sch C-2, Adj. 10, Sh 1	Line No.
1	Operating Revenue	$ (183,643,076)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2	Gas Cost	0	(201,173,630)	0	0	0	0	0	0	0	2
3	Operating Margin	$ (183,643,076)	$ 201,173,630	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	3
	Operating Expenses										
4	Other Gas Costs	$ 0	$ 0	$ 90,917	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	4
5	Storage	0	0	0	0	0	0	0	0	0	5
6	Distribution	0	0	2,382,071	0	(428,454)	42,775	0	0	0	6
7	Customer Accounts	0	0	843,661	73,158	(51,747)	0	(81,178)	0	0	7
8	Customer Service & Info.	0	0	0	0	(45,406)	0	0	0	0	8
9	Sales	0	0	0	0	(5,050)	0	0	0	0	9
	Administrative & General										
10	Direct	0	0	16,191	0	(2,460)	0	0	790,608	0	10
11	System Allocable	0	0	276,857	0	(596,418)	288,231	0	(238,800)	(12,011)	11
	Depreciation & Amortization										
12	Direct	0	0	0	0	0	0	0	0	0	12
13	System Allocable	0	0	0	0	0	0	0	0	0	13
14	Regulatory Amortizations	0	0	0	0	0	0	0	0	0	14
15	Taxes Other Than Income	0	0	0	0	0	0	0	0	0	15
16	Interest on Customer Deposits	0	0	0	0	0	0	0	0	0	16
17	Total Operating Expenses	$ 0	$ 0	$ 3,609,697	$ 73,158	$ (1,129,536)	$ 331,007	$ (81,178)	$ 551,808	$ (12,011)	17
18	Net Operating Income	$ (183,643,076)	$ 201,173,630	$ (3,609,697)	$ (73,158)	$ 1,129,536	$ (331,007)	$ 81,178	$ (551,808)	$ 12,011	18
	Rate Base										
	Gas Plant in Service										
19	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ (229,604)	$ 0	$ 0	$ 0	19
20	System Allocable	0	0	0	0	0	(1,155,419)	0	0	0	20
21	Total Gas Plant in Service	$ 0	$ 0	$ 0	$ 0	$ 0	$ (1,385,023)	$ 0	$ 0	$ 0	21
	Accumulated Provision for Depr and Amorts										
22	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ (104,738)	$ 0	$ 0	$ 0	22
23	System Allocable	0	0	0	0	0	(527,791)	0	0	0	23
24	Total Accumulated Provision	$ 0	$ 0	$ 0	$ 0	$ 0	$ (632,529)	$ 0	$ 0	$ 0	24
25	Net Plant in Service	$ 0	$ 0	$ 0	$ 0	$ 0	$ (752,493)	$ 0	$ 0	$ 0	25
	Other Rate Base										
	Allowance for Working Capital										
26	Cash Working Capital	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	26
27	Materials and Supplies	0	0	0	0	0	0	0	0	0	27
28	Prepayments	0	0	0	0	0	0	0	0	0	28
29	Customer Deposits	0	0	0	0	0	0	0	0	0	29
30	Customer Advances	0	0	0	0	0	0	0	0	0	30
31	Deferred Taxes	0	0	0	0	0	0	0	0	0	31
32	Total Other Rate Base	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	32
33	Total Rate Base	$ 0	$ 0	$ 0	$ 0	$ 0	$ (752,493)	$ 0	$ 0	$ 0	33

SOUTHWEST GAS CORPORATION
ARIZONA
ITEMIZATION OF PRO FORMA ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Paiute Alloc. Annualization Adj. No. 11	Rate Case Expense Adj. No. 12	Dep/Amort Expense Adj. No. 13	Taxes Other Than Income Adj. No. 14	Interest on Customer Dep. Adj. No. 15	Regulatory Amortizations Adj. No. 16	Post-Test Year Plant Adj. No. 17	LNG Adj. No. 18	Deferred Taxes Adj. No. 19	Total of Adjustments	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
		Sch C-2, Adj. 11, Sh 1	Sch C-2, Adj. 12, Sh 1	Sch C-2, Adj. 13, Sh 1-4	Sch C-2, Adj. 14, Sh 1	Sch C-2, Adj. 15, Sh 1	Sch C-2, Adj. 16, Sh 1	Sch B-2, Adj. 17, Sh 1 Sch B-2, Adj. 17, Sh 2	Sch B-2, Adj. 18, Sh 1	B-2, Adj. 19, Sh 1		
1	Operating Revenue	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (183,643,076)	1
2	Gas Cost	0	0	0	0	0	0	0	0	0	(201,173,630)	2
3	Operating Margin	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 17,530,554	3
	Operating Expenses											
4	Other Gas Costs	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 90,917	4
5	Storage	0	0	0	0	0	0	0	1,470,088	0	1,470,088	5
6	Distribution	0	0	0	0	0	0	0	0	0	1,996,392	6
7	Customer Accounts	0	0	0	0	0	0	0	0	0	783,894	7
8	Customer Service & Info.	0	0	0	0	0	0	0	0	0	(45,406)	8
9	Sales	0	0	0	0	0	0	0	0	0	(5,050)	9
	Administrative & General											
10	Direct	0	70,108	0	0	0	0	0	0	0	874,447	10
11	System Allocable	(290,345)	0	0	0	0	0	0	0	0	(572,485)	11
	Depreciation & Amortization											
12	Direct	0	0	10,835,680	0	0	0	0	0	0	10,835,680	12
13	System Allocable	0	0	3,544,503	0	0	0	0	0	0	3,544,503	13
14	Regulatory Amortizations	0	0	0	0	0	(10,198,917)	0	0	0	(10,198,917)	14
15	Taxes Other Than Income	0	0	0	15,911,411	0	0	0	0	0	15,911,411	15
16	Interest on Customer Deposits	0	0	0	0	(1,222,444)	0	0	0	0	(1,222,444)	16
17	Total Operating Expenses	$ (290,345)	$ 70,108	$ 14,380,183	$ 15,911,411	$ (1,222,444)	$ (10,198,917)	$ 0	$ 1,470,088	$ 0	$ 23,463,029	17
18	Net Operating Income	$ 290,345	$ (70,108)	$ (14,380,183)	$ (15,911,411)	$ 1,222,444	$ 10,198,917	$ 0	$ (1,470,088)	$ 0	$ (5,932,475)	18
											Sch C-1, Sh 1, Col (d)	
	Rate Base											
	Gas Plant in Service											
19	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 103,494,011	$ 76,200,000	$ 0	$ 179,464,406	19
20	System Allocable	0	0	0	0	0	0	35,436,594	0	0	34,281,176	20
21	Total Gas Plant in Service	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 138,930,605	$ 76,200,000	$ 0	$ 213,745,582	21
	Accumulated Provision for Depr and Amorts											
22	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (104,738)	22
23	System Allocable	0	0	0	0	0	0	0	0	0	(527,791)	23
24	Total Accumulated Provisio	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (632,529)	24
25	Net Plant in Service	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 138,930,605	$ 76,200,000	$ 0	$ 214,378,112	25
	Other Rate Base											
	Allowance for Working Capital											
26	Cash Working Capital	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	26
27	Materials and Supplies	0	0	0	0	0	0	0	2,800,000	0	2,800,000	27
28	Prepayments	0	0	0	0	0	0	0	0	0	0	28
29	Customer Deposits	0	0	0	0	0	0	0	0	0	0	29
30	Customer Advances	0	0	0	0	0	0	0	0	0	0	30
31	Deferred Taxes	0	0	0	0	0	0	0	0	1,518,173	1,518,173	31
32	Total Other Rate Base	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,800,000	$ 1,518,173	$ 4,318,173	32
33	Total Rate Base	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 138,930,605	$ 79,000,000	$ 1,518,173	$ 218,696,285	33

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SALES, TRANSPORTATION QUANTITY AND REVENUES - ADJUSTMENT NO. 1
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Recorded At 01/31/2019	Adjustment No. 1	Test Period Balance As Adjusted	Line No.
	(a)	(b)	(c)	(d)	
1	Sales Quantity (Therms)	529,437,882	(9,122,664)	520,315,218	1
2	Transportation Quantity (Therms)	176,295,686	(138,283)	176,157,403	2
3	Total Quantity	705,733,568	(9,260,947)	696,472,621	3
4	Revenue	$ 701,861,440	$ (183,643,076)	$ 518,218,363	4
5	Total Revenue Adjustment		$ (183,643,076)		5

Explanation:
To adjust for changes in number of bills and sales volumes, to adjust revenues to authorized levels, to reverse unbilled revenues, and to remove gas cost from the cost of service.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
PURCHASED GAS COST - ADJUSTMENT NO. 2
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	FERC Account Number		Amount	Line No.
	(a)	(b)		(c)	
1	Natural Gas Transmission Line Purchases	803.00	$	116,448,762	1
2	Purchased Gas Cost Adjustments	805.10		77,881,083	2
3	Gas Withdrawn from Storage	808.10		226,519	3
4	Gas Delivered to Storage	808.20		(16,523)	4
5	Gas Used for Compressor Station Fuel	810.00		0	5
6	Transmission and Compression of Gas	858.00		6,633,789	6
7	Total Adjustment No. 2 - Recorded Cost of Purchased Gas		$	201,173,630	7
8	Present Volume Adjustment			(3,466,393)	8
9	Present Rate Adjustment			(16,107,784)	9
10	Subtotal of Adjustments			(19,574,177)	10
11	Total Cost of Purchased Gas Adjusted at Present Rates		$	181,599,453	11

Explanation:
To adjust for changes in sales volumes and to adjust the average cost of purchased gas to match the average cost of purchased gas included in currently effective base tariff sales rates.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
COST OF PURCHASED GAS - ADJUSTED AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Recorded Total	Volume Adjustment Sales	Volume Adjustment Gas Engines	Volume Adjustment Optional	Rate Adjustment Sales	Rate Adjustment Gas Engines	Rate Adjustment Optional	Adjusted Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
1	Sales Volumes (Therms)	529,437,882	(9,121,641)	(1,023)	0	497,583,394	13,307,582	9,424,242	520,315,218	1
2	Recorded Average Cost of Purchased Gas	$ 0.37998	$ 0.37998	$ 0.37998	$ 0.37998	$ 0.37998	$ 0.37998	$ 0.37998		2
3	Cost of Purchased Gas [1]					$ 0.35399	$ 0.18273	$ 0.32132		3
4	Change in Average Cost of Purchased Gas					$ (0.02599)	$ (0.19725)	$ (0.05865)		4
5	Cost of Purchased Gas	$ 201,173,630	$ (3,466,004)	$ (389)	$ 0	$ (12,930,147)	$ (2,624,866)	$ (552,771)	$ 181,599,453	5

[1] Cost of gas effective on January 31, 2019 excluding surcharges. Optional cost of purchased gas is average cost during test year.

SOUTHWEST GAS CORPORATION
ARIZONA
LABOR AND LABOR LOADING ANNUALIZATION
ADJUSTMENT NO. 3

Line No.	Description (a)	Labor (b)	Labor Loading (c)	Total (d)	Line No.
		WP C-2 Adj 3, Sh 1 thru 3, Col (h)	WP C-2 Adj 3, Sh 1 thru 3, Col (i)	(b) + (c)	
	Operations				
1	Account 813	$ 64,852	$ 26,065	$ 90,917	1
2	Account 840	0	0	0	2
3	Account 841	0	0	0	3
4	Account 850	0	0	0	4
5	Account 851	0	0	0	5
6	Account 852	0	0	0	6
7	Account 853	0	0	0	7
8	Account 856	0	0	0	8
9	Account 857	0	0	0	9
10	Account 859	0	0	0	10
11	Account 870	273,694	61,450	335,144	11
12	Account 871	29,631	12,463	42,095	12
13	Account 874	127,659	27,929	155,588	13
14	Account 875	49,406	10,978	60,383	14
15	Account 878	209,014	45,423	254,436	15
16	Account 879	357,141	101,285	458,427	16
17	Account 880	207,052	56,903	263,955	17
18	Account 901	82,618	33,046	115,664	18
19	Account 902	33,765	7,429	41,194	19
20	Account 903	474,495	208,294	682,789	20
21	Account 905	3,272	742	4,014	21
22	Account 908	0	0	0	22
23	Account 910	0	0	0	23
24	Account 920	985,312	639,300	1,624,612	24
25	Account 922	(145,880)	(94,651)	(240,531)	25
26	Account 930.2	0	0	0	26
27	Total Operations	$ 2,752,030	$ 1,136,656	$ 3,888,686	27
	Maintenance				
28	Account 863	$ 0	$ 0	$ 0	28
29	Account 885	62,278	13,698	75,976	29
30	Account 886	465	108	573	30
31	Account 887	317,150	70,076	387,226	31
32	Account 889	50,693	11,153	61,846	32
33	Account 892	159,533	35,458	194,991	33
34	Account 893	67,244	14,543	81,788	34
35	Account 894	7,905	1,739	9,645	35
36	Account 935 - Direct	12,635	3,557	16,191	36
37	Account 935 - System Alloc.	16,556	10,620	27,176	37
38	Total Maintenance	$ 694,459	$ 160,952	$ 855,411	38
39	Total O&M	$ 3,446,489	$ 1,297,608	$ 4,744,097	39
				Sch C-2, Sh 1, Col (d)	
	Functionalization				
40	Other Gas Supply	$ 64,852	$ 26,065	$ 90,917	40
41	Storage	0	0	0	41
42	Transmission	0	0	0	42
43	Distribution	1,918,865	463,206	2,382,071	43
44	Customer Accounts	594,150	249,511	843,661	44
45	Customer Service & Info.	0	0	0	45
46	Sales	0	0	0	46
47	A&G - Direct	12,635	3,557	16,191	47
48	A&G - Sys. Alloc.	855,988	555,269	1,411,257	48
49	Total	$ 3,446,489	$ 1,297,608	$ 4,744,097	49

To annualize labor and labor-related loadings as of January 31, 2019 to reflect within-grade increases through February 01, 2020 and a 2.7% general wage increase effective June 2019.

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF NON-SERVICE RETIREMENT BENEFITS COSTS
LABOR AND BENEFITS ANNUALIZATION
ADJUSTMENT NO. 3

Line No.	Description	Reference	Pension	PBOP	SERP	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f) (c)+(d)+(e)	
1	Normalized Total Retirement Benefits Cost	Actuarial Studies	$ 40,451,002	$ 2,317,151	$ 3,361,807		1
2	Normalized Current Service Cost	WP C-2 Adj 3, Sh 43	25,936,943	1,405,396	273,341		2
3	Normalized Non-Service Cost	Ln 1 - Ln 2	$ 14,514,059	$ 911,756	$ 3,088,466	$ 18,514,280	3
4	Recorded Non-Service Cost	Company Records				20,647,761	4
5	Adjustment	Ln 3 - Ln 4				$ (2,133,481)	5
6	Less: MMF Allocation	Sch C-1, Sh 18, Ln 7(i)+(j)				4.50%	6
7	Adjustment after MMF Allocation	Ln 5 * (1 - Ln 6)				$ (2,037,442)	7
8	Allocation to Arizona	Sch C-1, Sh 17, Ln 9(c)				55.68%	8
9	Amount After Allocation	Ln 7 * Ln 8				$ (1,134,401)	9
						Sch C-2, Sh 1, Col (d)	

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
CALL CENTER AND SUPPORT FUNCTION ALLOCATION
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
ADJUSTMENT NO. 4

Line No.	Description	Reference	AZ	SCA	NCA	SLT	SNV	NNV	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
									Sum (c)-(h)	
	Account 903									
1	903001777 - Call Center	Company Records	$ 3,838,967	$ 497,348	$ 91,474	$ 67,759	$ 2,183,952	$ 325,919	$ 7,005,418	1
2	903001778 - Support Function	Company Records	1,345,434	197,588	34,097	94,403	814,029	389,878	2,875,430	2
3	Total as Recorded	Ln 1 + Ln 2	$ 5,184,401	$ 694,936	$ 125,571	$ 162,162	$ 2,997,981	$ 715,796	$ 9,880,848	3
4	Factor IV	Sch C-1, Sh 17, Ln 8	53.21%	7.30%	1.34%	0.99%	32.38%	4.78%	100.00%	4
5	Total as Allocated	Ln 4 * Ln 3(i)	$ 5,257,559	$ 721,334	$ 132,559	$ 97,989	$ 3,199,257	$ 472,149	$ 9,880,848	5
6	Adjustment	Ln 5 - Ln 3	$ 73,158	$ 26,398	$ 6,988	$ (64,173)	$ 201,276	$ (243,648)	$ 0	6
			Sch C-2, Sh 1 Col (e)							

SOUTHWEST GAS CORPORATION
ARIZONA
COST OF SERVICE ANALYSIS
ADJUSTMENT NO. 5

Line No.	Account Number	Reference	Expenses Removed: Donation/ Civic Activity	Employee Events	Employee Recognition	Other Emp. Welfare	Sponsorships, Ads, Promo.	Retirement Gift/Meals	Non-Utility Expense	Non-Recurring Expense	Out of Period Expenses	Expense Annualization	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m) Sum (c)-(l)	
1	870	WP C-2, Adj. 5, Sh 1	$ (82)	$ 0	$ 0	$ 0	$ (1,636)	$ 0	$ (23,767)	$ (208,074)	$ 0	$ 0	$ (233,560)	1
2	874	WP C-2, Adj. 5, Sh 18	0	0	0	0	0	0	(230)	0	0	0	(230)	2
3	880	WP C-2, Adj. 5, Sh 3	(10,209)	(5,712)	0	0	(6,702)	(2,835)	(86,436)	0	0	15,256	(96,638)	3
4	881	WP C-2, Adj. 5, Sh 4	0	0	0	0	0	0	0	0	0	(89,800)	(89,800)	4
5	885	WP C-2, Adj. 5, Sh 18	0	0	0	0	0	0	(4,888)	0	0	0	(4,888)	5
6	887	WP C-2, Adj. 5, Sh 18	0	0	0	0	0	0	(840)	0	0	0	(840)	6
7	901	WP C-2, Adj. 5, Sh 18	0	0	0	0	0	0	(44)	0	0	0	(44)	7
8	903	WP C-2, Adj. 5, Sh 5	0	0	0	0	(16,750)	(2,500)	(22,847)	0	0	0	(42,097)	8
9	908	WP C-2, Adj. 5, Sh 6	0	0	0	0	0	0	(24,142)	0	0	0	(24,142)	9
10	910	WP C-2, Adj. 5, Sh 7	(1,000)	0	0	0	(700)	0	0	0	0	(5,017)	(6,717)	10
11	913	WP C-2, Adj. 5, Sh 8	(5,050)	0	0	0	0	0	0	0	0	0	(5,050)	11
12	930.1	WP C-2, Adj. 5, Sh 18	0	0	0	0	0	0	(904)	0	0	0	(904)	12
13	935	WP C-2, Adj. 5, Sh 18	0	0	0	0	0	0	(1,557)	0	0	0	(1,557)	13
14	Total	Sum Lns 1-13	$ (16,341)	$ (5,712)	$ 0	$ 0	$ (25,788)	$ (5,335)	$ (165,654)	$ (208,074)	$ 0	$ (79,561)	$ (506,467)	14
													Sch C-2, Sh 1, Col (f)	

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
COST OF SERVICE ANALYSIS
ADJUSTMENT NO. 5

Line No.	Account Number	Reference	Expenses Removed: Donation/ Civic Activity	Employee Events	Employee Recognition	Other Emp. Welfare	Sponsorships, Ads, Promo.	Retirement Gift/Meals	Non-Utility Expense	Non-Recurring Expense	Out of Period Expenses	Expense Annualization	Total	MMF	Amount Before Alloc. to AZ	AZ Alloc. Factor	Amount After Alloc. to AZ
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
														Sch C-1, Sh 18	(m) * [1- (n)]	Sch C-1, Sh 17	(o) * (p)
1	870	WP C-2, Adj. 5, Sh 18	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (326)	$ 0	$ 0	$ 0	$ (326)	n/a	$ (326)	53.21%	$ (174)
2	880	WP C-2, Adj. 5, Sh 9	(950)	0	0	0	0	0	(3,417)	0	0	0	(4,367)	n/a	(4,367)	53.21%	(2,324)
3	901	WP C-2, Adj. 5, Sh 18	0	0	0	0	0	0	(1,306)	0	0	0	(1,306)	n/a	(1,306)	53.21%	(695)
4	903	WP C-2, Adj. 5, Sh 10	0	0	0	0	(14,048)	(2,700)	0	0	0	0	(16,748)	n/a	(16,748)	53.21%	(8,911)
5	908	WP C-2, Adj. 5, Sh 18	0	0	0	0	0	0	(40)	0	0	0	(40)	n/a	(40)	53.21%	(21)
6	910	WP C-2, Adj. 5, Sh 11	0	0	0	0	0	0	(27,300)	0	0	0	(27,300)	n/a	(27,300)	53.21%	(14,526)
7	920	Company Records [1]	0	0	0	0	0	0	(343,192)	0	0	0	(343,192)	4.50%	(327,743)	55.68%	(182,480)
8	921	WP C-2, Adj 5, Sh 14	(1,000)	0	(2,990)	0	(65,725)	0	(260,374)	0	(4,483)	(40,165)	(374,737)	4.50%	(357,868)	55.68%	(199,253)
9	923	WP C-2, Adj. 5, Sh 15	0	0	0	0	0	0	(39,854)	0	(405,443)	70,078	(375,218)	4.50%	(358,328)	55.68%	(199,509)
10	930.2	WP C-2, Adj. 5, Sh 16	0	0	0	0	0	(2,984)	0	0	0	0	(2,984)	4.50%	(2,850)	55.68%	(1,587)
11	931	WP C-2, Adj. 5, Sh 17	0	0	0	0	0	0	(32,292)	0	0	6,733	(25,559)	4.50%	(24,408)	55.68%	(13,590)
12	Total	Sum Lns 1-11	$ (1,950)	$ 0	$ (2,990)	$ 0	$ (79,773)	$ (5,684)	$ (708,101)	$ 0	$ (409,926)	$ 36,646	$ (1,171,777)		$ (1,121,284)		$ (623,069)
																	Sch C-2, Sh 1, Col (f)

[1] Removes the non-utility portion certain compensation for Strategy Executives.

SOUTHWEST GAS CORPORATION
ARIZONA
EMPLOYEE VEHICLE COMPENSATION
RATE BASE
ADJUSTMENT NO. 6

			Remove Company-Owned Vehicles					
Line No.	Description	Reference	Original Cost	Accum. Reserve	Deferred Taxes	Rate Base	Amortization Expense [1]	Line No.
	(a)	(b)	(c)	(d)	(e)	(f) (c) + (d) + (e)	(g)	
1	Arizona	Company Records	$ (229,604)	$ 104,738	$ 7,169	$ (117,697)	$ (32,994)	1
2	System Allocable	Company Records	$ (2,075,191)	$ 947,940	$ 35,565	$ (1,091,686)	$ (215,197)	2
3	AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)	55.68%	55.68%	55.68%	55.68%	55.68%	3
4	Adjustment Allocated to AZ	Ln 2 * Ln 3	$ (1,155,419)	$ 527,791	$ 19,802	$ (607,826)	$ (119,817)	4
5	Total Adjustment	Ln 1 + Ln 4	$ (1,385,023)	$ 632,529	$ 26,971	$ (725,523) Sch C-2, Sh 1, Col (g)	$ (152,811)	5

Explanation:
To remove company-owned vehicles used by Directors and above and include annualized stipend portion of compensation per current Company policy.

[1] Removed automatically in the Company's depreciation and annualization adjustment as a result of the adjustment to rate base.

SOUTHWEST GAS CORPORATION
ARIZONA
EMPLOYEE VEHICLE COMPENSATION
OPERATING EXPENSES
ADJUSTMENT NO. 6

Line No.	Description	Reference	Remove Vehicle O&M	Add Stipend	Total Adjustment	Line No.
	(a)	(b)	(c)	(d)	(e)	
					Sum (c)-(d)	
1	Arizona	Company Records	$ (31,625)	$ 74,400	$ 42,775	1
2	System Allocable	Company Records	$ (109,520)	$ 651,600	$ 542,080	2
3	Less: MMF Allocation	Sch C-1, Sh 18, Ln 7(i)+(j)	4.50%	4.50%	4.50%	3
4	Adjustment after MMF Allocation	Ln 2 * Ln 3	$ (104,590)	$ 622,268	$ 517,678	4
5	AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)	55.68%	55.68%	55.68%	5
6	Adjustment Allocated to AZ	Ln 4 * Ln 5	$ (58,233)	$ 346,464	$ 288,231	6
7	Total Adjustment	Ln 1 + Ln 6	$ (89,858)	$ 420,864	$ 331,007	7
					Sch C-2, Sh 1, Col (g)	

Explanation:
To remove company-owned vehicles used by Directors and above and include annualized stipend portion of compensation per current Company policy.

SOUTHWEST GAS CORPORATION
ARIZONA
UNCOLLECTIBLES EXPENSE ANNUALIZATION
ADJUSTMENT NO. 7

Line No.	Description	Reference	Account Number	Amount	Line No.
	(a)	(b)	(c)	(d)	
1	Revenue at Present Rates	Sch H-2, Sh 4		$ 699,817,817	1
2	Write-Off Percent of Revenue	WP Sch C-2, Adj. 7, Sh 1		0.1930%	2
3	Annualized Uncollectible Expense	Ln 1 * Ln 2		$ 1,350,724	3
4	Less: Recorded Uncollectible Expense	Sch C-1, Sh 3, Ln 29(c)	904	1,431,902	4
5	Adjustment	Ln 3 - Ln 4	904	$ (81,178)	5
				Sch C-2, Sh 1, Col (h)	

SOUTHWEST GAS CORPORATION
ARIZONA
SELF-INSURED RETENTION NORMALIZATION
ADJUSTMENT NO. 9

Line No.	Description	Reference	Account Number		Amount	Line No.
	(a)	(b)	(c)		(d)	
1	Arizona	Sch C-2, Adj. 9, Sh 2, Ln 7(c)	925	$	790,608	1
2	System Allocable	Sch C-2, Adj. 9, Sh 2, Ln 7(d)	925	$	(449,115)	2
3	Less: MMF Allocation	Sch C-1, Sh 18, Ln 7(i)+(j)			4.50%	3
4	Adjustment after MMF Allocation	Ln 2 * (1 - Ln 3)		$	(428,898)	4
5	AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)			55.68%	5
6	Adjustment Allocated to AZ	Ln 4 * Ln 5		$	(238,800)	6
7	Total Adjustment	Ln 1 + Ln 6		$	551,808	7
					Sch C-2, Sh 1, Col (i)	

SOUTHWEST GAS CORPORATION
ARIZONA
SELF-INSURED RETENTION NORMALIZATION
ADJUSTMENT NO. 9

Line No.	Description	Reference	AZ Direct	System Allocable	Line No.
	(a)	(b)	(c)	(d)	
	Claims Paid				
1	< $1,000,000	WP C-2, Adj. 9, Sh 1, Ln 11	$ 2,906,080	$ 1,508,854	1
2	at $1,000,000	WP C-2, Adj. 9, Sh 1, Ln 22	1,000,000	0	2
3	$4,000,000 Aggregate	WP C-2, Adj. 9, Sh 1, Ln 33	4,000,000	0	3
4	Total Claims Paid	Sum Ln 1 - Ln 3	$ 7,906,080	$ 1,508,854	4
5	10-Year Average	Ln 4 /10	$ 790,608	$ 150,885	5
6	Recorded During Test Year	Company Records	0	600,000	6
7	Adjustment	Ln 5 - Ln 6	$ 790,608	$ (449,115)	7
			Sch C-2, Adj. 9, Sh 1, Ln 1(d)	Sch C-2, Adj. 9, Sh 1, Ln 2(d)	

SOUTHWEST GAS CORPORATION
ARIZONA
AMERICAN GAS ASSOCIATION DUES
REMOVE LOBBYING PERCENTAGE OF DUES
ADJUSTMENT NO. 10

Line No.	Description (a)	Reference (b)	Account Number (c)		Amount (d)	Line No.
1	2018 AGA Dues	Company Records	930.2	$	607,215	1
2	Lobbying Percentage	AGA Records			-3.72%	2
3	Lobbying Portion of AGA Dues	Ln 1 * Ln 2		$	(22,588)	3
4	Less: MMF Allocation	Sch C-1, Sh 18, Ln 7(i)+(j)			4.50%	4
5	Adjustment after MMF Allocation	Ln 3 * Ln 4		$	(21,572)	5
6	AZ 4-Factor	Sch C-1, Sh 17, Ln 9(c)			55.68%	6
7	Adjustment Allocated to AZ	Ln 5 * Ln 6		$	(12,011)	7
					Sch C-2, Sh 1, Col (j)	

SOUTHWEST GAS CORPORATION
ARIZONA
PAIUTE ALLOCATION ANNUALIZATION
ADJUSTMENT NO. 11

Line No.	Description	Ref/ Account Number	For The Twelve Months Ended January 31, 2019 Net Recorded	Charged to Paiute	Gross Recorded	Paiute MMF Allocation [1]	Paiute Annualized	Change to Alloc. of Paiute's A&G Expenses	AZ Allocation Factor [2]	Amount Allocated to AZ	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
			Sch C-1, Sh 9, Col (f)	Company Records	(c) + (d)	Sch C-1, Sh 18, Ln 7(i)	(e) * (f)	(d) - (g)	Sch C-1, Sh 17, Col (c)	(h) * (i)	
1	A&G Salaries	920	$ 86,302,652	$ 3,809,851	$ 90,112,503	4.47%	$ 4,027,413	$ (217,563)	55.68%	$ (121,134)	1
2	Office Supplies and Expenses	921	15,930,848	714,067	16,644,915	4.47%	743,914	(29,847)	55.68%	(16,618)	2
3	A&G Expenses Transferred (Credit)	922	(12,965,038)	(581,131)	(13,546,168)	4.47%	(605,421)	24,291	63.41%	15,403	3
4	Outside Services	923	26,349,646	1,218,432	27,568,078	4.47%	1,232,105	(13,673)	55.68%	(7,613)	4
5	Property Insurance	924	438,203	93,661	531,864	16.65%	88,561	5,100	56.16%	2,865	5
6	Injuries and Damages	925	11,606,430	536,871	12,143,301	4.47%	542,723	(5,852)	55.68%	(3,258)	6
7	Misc. General Expenses	930.2	6,218,321	0	6,218,321	4.47%	277,916	(277,916)	55.68%	(154,737)	7
8	Rents	931	3,392,047	152,260	3,544,306	4.47%	158,406	(6,147)	55.68%	(3,422)	8
9	Maint. Of General Plant	935	3,517,060	161,104	3,678,163	4.47%	164,389	(3,285)	55.68%	(1,829)	9
10	Total	Sum Lns 1-9	$ 140,790,169	$ 6,105,114	$ 146,895,283		$ 6,630,006	$ (524,892)		$ (290,345)	10
										Sch C-2, Sh 2, Col (b)	

[1] Account 924 is allocated using the insurable property factor calculated on WP C-2, Adj. 11, Sh 3.
[2] All accounts are allocated using the 4-Factor except Account 924, which is allocated using Factor II.

Note: Account 493, Rent from Gas Property, changed by $139,962 due to annualizing the Paiute rental charge at 1/31/2019 as calculated on WP C-2, Adj. 11, Sh 1.

SOUTHWEST GAS CORPORATION
ARIZONA
INCREMENTAL RATE CASE EXPENSE
ADJUSTMENT NO. 12

Line No.	Description (a)	Ref/ Account Number (b)		Amount (c)	Line No.
1	Printing/Copying/Postage/Freight	Estimate	$	150,000	1
2	Professional Services	Estimate		160,000	2
3	Notice/Publication	Estimate		35,000	3
4	Court Reporting	Estimate		1,000	4
5	Travel/Transportation/Misc.	Estimate		125,000	5
6	Total Rate Case Expense	Sum Lns 1-5	$	471,000	6
7	Amortization Period (Years)	[1]		3	7
8	Annual Rate Case Expense	928	$	157,000	8
9	Test Year Recorded Rate Case Expense	Sch C-1, Sh 9, Ln 11(d)		86,892	9
10	Adjustment	Ln 8 - Ln 9	$	70,108	10
				Sch C-2, Sh 2, Col (c)	

[1] The Company proposes to amortize rate case expense over a typical rate case cycle.

SOUTHWEST GAS CORPORATION
ARIZONA
DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
ADJUSTMENT NO. 13

Line No.	Description	Account Number	Gas Plant as Adjusted at 1/31/2019	Depreciation/ Amortization Rate	Annualized Depreciation/ Amortization	Recorded Depreciation/ Amortization	Adjustment	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
			WP B-2, Sh 1, Col (e)	Company Records	(c) * (d)	Company Records	(e) - (f)	
	Intangible Plant							
1	Organization	301	$ 42,653	Amortized	$ 0	$ 0	$ 0	1
2	Franchise and Consents	302	2,208,574	Amortized	71,779 [1]	71,779	0	2
3	Miscellaneous Intangible	303	1,968,623	Amortized	0	0	0	3
4	Total Intangible Plant		$ 4,219,850		$ 71,779	$ 71,779	$ 0	4
	Storage Plant							
5	Land and Land Rights	360	$ 1,772,673	N/A	$ 0	$ 0	$ 0	5
6	Structures and Improvements	361	76,200,000	4.75%	3,619,500	0	3,619,500	6
7	Liquifaction Equipment	363.1	0	4.75%	0	0	0	7
8	Vaporizing Equipment	363.2	0	4.75%	0	0	0	8
9	Compressor Maintenance	363.3	0	4.75%	0	0	0	9
10	Other Equipment	363.5	0	4.75%	0	0	0	10
11	Total Storage Plant		$ 77,972,673		$ 3,619,500	$ 0	$ 3,619,500	11
	Distribution Plant							
12	Land and Land Rights	374.1	$ 405,666	N/A	$ 0	$ 0	$ 0	12
13	Rights of Way	374.2	3,312,434	1.37%	45,380	44,679	701	13
14	Structures and Improvements	375	110,557	3.35%	3,704	3,704	(0)	14
15	Mains	376	2,160,289,144	1.81%	39,101,233	35,599,210	3,502,023	15
16	Measuring and Reg. Stations	378	84,676,781	3.87%	3,276,991	3,150,223	126,769	16
17	Services	380	1,044,141,707	2.82%	29,444,796	27,537,490	1,907,306	17
18	Meters	381	307,551,428	4.15%	12,763,384	12,381,919	381,465	18
19	Industrial Measuring and Reg. Sta.	385	12,445,142	1.78%	221,524	222,651	(1,127)	19
20	Miscellaneous Equipment	387	432,098	0.00%	0	22,728	(22,728)	20
21	Total Distribution Plant		$ 3,613,364,956		$ 84,857,013	$ 78,962,604	$ 5,894,409	21
	General Plant							
22	Land and Land Rights	389	$ 17,212,657	N/A	$ 0	$ 0	$ 0	22
23	Structures and Improv - Co. Owned	390.1	73,397,387	2.79%	2,047,787	1,576,801	470,986	23
24	Structures and Improv - Leasehold	390.2	128,051	Amortized	8,221	8,221	0	24
25	Office Furniture and Fixtures	391	5,936,198	7.29%	432,749	389,829	42,919	25
26	Computer Software and Hardware	391.1	17,677,300	21.94%	3,878,400	3,804,451	73,948	26
27	Transportation Equipment - Light	392.11	24,641,620	14.37%	3,541,001	3,377,899	163,102	27
28	Transportation Equipment - Heavy	392.12	17,004,439	4.07%	692,081	647,457	44,624	28
29	Stores Equipment	393	939,126	3.73%	35,029	31,993	3,036	29
30	Tool, Shop, and Garage Equip.	394	16,529,870	10.39%	1,717,453	1,192,789	524,664	30
31	Laboratory Equipment	395	557,187	5.48%	30,534	30,743	(209)	31
32	Power-Operated Equipment	396	9,006,861	3.46%	311,637	299,515	12,123	32
33	Communication Equipment	397	3,194,627	-1.11%	(35,460)	(22,683)	(12,777)	33
34	Telemetry Equipment	397.2	163,887	21.96%	35,990	42,716	(6,726)	34
35	Miscellaneous Equipment	398	2,093,352	6.38%	133,556	127,475	6,081	35
36	Total General Plant		$ 188,482,563		$ 12,828,977	$ 11,507,206	$ 1,321,771	36
37	Total Depreciation		$ 3,879,692,140		$ 101,297,269	$ 90,461,589	$ 10,835,680	37
38	Total Amortization		4,347,901		80,000	80,000	0	38
39	Total Depreciation and Amortization		$ 3,884,040,042		$ 101,377,269	$ 90,541,589	$ 10,835,680	39
							Sch C-2, Sh 2, Col (d)	

[1] Annualized amortization expense in Acct 302 based on January 2019 amortization * 12.

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
DEPRECIATION AND ANNUALIZATION EXPENSE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
ADJUSTMENT NO. 13

Line No.	Description	Account Number	Gas Plant as Adjusted at 1/31/2019	Depreciation/ Amortization Rate	Annualized Depreciation/ Amortization	Recorded Depreciation/ Amortization	Adjustment before Alloc. to AZ	Adjustment after Alloc. to AZ	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
			WP B-2, Sh 5, Col (e)	Company Records	(c) * (d)	Company Records	(e) - (f)	(g) * Ln 23(c)	
	Intangible Plant								
1	Organization	301	$ 61,816	Amortized	$ 0	$ 0	$ 0	$ 0	1
2	Miscellaneous Intangible	303	266,767,655	Amortized	18,216,545	13,382,745	4,833,800 [1]	2,691,348	2
3	Total Intangible Plant		$ 266,829,471		$ 18,216,545	$ 13,382,745	$ 4,833,800	$ 2,691,348	3
	General Plant								
4	Land and Land Rights	389	$ 6,223,947	N/A	$ 0	$ 0	$ 0	$ 0	4
5	Structures and Improv - Co. Owned	390.1	53,818,778	2.30%	1,237,832	802,938	434,894	242,139	5
6	Structures and Improv - Leasehold	390.2	4,354,821	Amortized	536,078	240,069	296,009	164,811	6
7	Office Furniture and Fixtures	391	9,353,663	6.67%	623,889	560,179	63,710	35,472	7
8	Computer Software and Hardware	391.1	21,779,871	20.00%	4,355,974	3,698,713	657,261	365,948	8
9	Transportation Equipment - Light	392.11	2,907,447	10.37%	301,502	357,308	(55,806)	(31,071)	9
10	Transportation Equipment - Heavy	392.12	0	10.37%	0	0	0	0	10
11	Transportation Equipment - Aircraft	392.21	8,221,361	4.00%	328,854	328,854	(0)	(0)	11
12	Stores Equipment	393	63,037	6.67%	4,205	4,205	0	0	12
13	Tool, Shop, and Garage Equip.	394	1,106,311	6.67%	73,791	72,044	1,747	973	13
14	Laboratory Equipment	395	1,262,929	5.00%	63,146	55,646	7,500	4,176	14
15	Power-Operated Equipment	396	11,760	5.66%	666	666	(0)	(0)	15
16	Communication Equipment	397	7,468,337	6.67%	498,138	408,930	89,209	49,669	16
17	Telemetry Equipment	397.2	2,241	16.66%	373	373	(0)	(0)	17
18	Miscellaneous Equipment	398	3,021,779	6.67%	201,553	86,322	115,231	64,158	18
19	Total General Plant		$ 119,596,281		$ 8,226,002	$ 6,616,247	$ 1,609,755	$ 896,275	19
20	Total Depreciation		$ 115,241,460		$ 7,689,924	$ 6,376,178	$ 1,313,746	$ 731,463	20
21	Total Amortization		271,184,292		18,752,623	13,622,814	5,129,809	2,856,160	21
22	Total Depreciation and Amortization		$ 386,425,753		$ 26,442,547	$ 19,998,992	$ 6,443,555	$ 3,587,623	22
								Sch C-2, Sh 2, Col (d)	
23	AZ 4-Factor		55.68%						23

[1] WP B-2, Adj. 13, Sh 7, Ln 499(n) + WP B-2, Adj. 17, Sh 3, Ln 34(f)

SOUTHWEST GAS CORPORATION
ARIZONA
DEPRECIATION AND ANNUALIZATION EXPENSE AT NEW RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
ADJUSTMENT NO. 13

Line No.	Description	Account Number	Gas Plant as Adjusted at 1/31/2019	Depreciation/ Amortization New Rates	Adjusted Depreciation/ Amortization	Annualized Depreciation/ Amortization	Adjustment	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
			WP B-2, Sh 1, Col (e)	No study filed	(c) * (d)	Sch C-2, Adj. 13, Sh 1 Col(e)	(e) - (f)	
	Intangible Plant							
1	Organization	301	$ 42,653	Amortized	$ 0	$ 0	$ 0	1
2	Franchise and Consents	302	2,208,574	Amortized	71,779	71,779	0	2
3	Miscellaneous Intangible	303	1,968,623	Amortized	0	0	0	3
4	Total Intangible Plant		$ 4,219,850		$ 71,779	$ 71,779	$ 0	4
	Storage Plant							
5	Land and Land Rights	360	$ 1,772,673	N/A	$ 0	$ 0	$ 0	5
6	Structures and Improvements	361	76,200,000	4.75%	3,619,500	3,619,500	0	6
7	Liquifaction Equipment	363.1	0	4.75%	0	0	0	7
8	Vaporizing Equipment	363.2	0	4.75%	0	0	0	8
9	Compressor Maintenance	363.3	0	4.75%	0	0	0	9
10	Other Equipment	363.5	0	4.75%	0	0	0	10
11	Total Storage Plant		$ 77,972,673		$ 3,619,500	$ 3,619,500	$ 0	11
	Distribution Plant							
12	Land and Land Rights	374.1	$ 405,666	N/A	$ 0	$ 0	$ 0	12
13	Rights of Way	374.2	3,312,434	1.37%	45,380	45,380	0	13
14	Structures and Improvements	375	110,557	3.35%	3,704	3,704	0	14
15	Mains	376	2,160,289,144	1.81%	39,101,233	39,101,233	0	15
16	Measuring and Reg. Stations	378	84,676,781	3.87%	3,276,991	3,276,991	0	16
17	Services	380	1,044,141,707	2.82%	29,444,796	29,444,796	0	17
18	Meters	381	307,551,428	4.15%	12,763,384	12,763,384	0	18
19	Industrial Measuring and Reg. Sta.	385	12,445,142	1.78%	221,524	221,524	0	19
20	Miscellaneous Equipment	387	432,098	0.00%	0	0	0	20
21	Total Distribution Plant		$ 3,613,364,956		$ 84,857,013	$ 84,857,013	$ 0	21
	General Plant							
22	Land and Land Rights	389	$ 17,212,657	N/A	$ 0	$ 0	$ 0	22
23	Structures and Improv - Co. Owned	390.1	73,397,387	2.79%	2,047,787	2,047,787	0	23
24	Structures and Improv - Leasehold	390.2	128,051	Amortized	8,221	8,221	0	24
25	Office Furniture and Fixtures	391	5,936,198	7.29%	432,749	432,749	0	25
26	Computer Software and Hardware	391.1	17,677,300	21.94%	3,878,400	3,878,400	0	26
27	Transportation Equipment - Light	392.11	24,641,620	14.37%	3,541,001	3,541,001	0	27
28	Transportation Equipment - Heavy	392.12	17,004,439	4.07%	692,081	692,081	0	28
29	Stores Equipment	393	939,126	3.73%	35,029	35,029	0	29
30	Tool, Shop, and Garage Equip.	394	16,529,870	10.39%	1,717,453	1,717,453	0	30
31	Laboratory Equipment	395	557,187	5.48%	30,534	30,534	0	31
32	Power-Operated Equipment	396	9,006,861	3.46%	311,637	311,637	0	32
33	Communication Equipment	397	3,194,627	-1.11%	(35,460)	(35,460)	0	33
34	Telemetry Equipment	397.2	163,887	21.96%	35,990	35,990	0	34
35	Miscellaneous Equipment	398	2,093,352	6.38%	133,556	133,556	0	35
36	Total General Plant		$ 188,482,563		$ 12,828,977	$ 12,828,977	$ 0	36
37	Total Depreciation		$ 3,879,692,140		$ 101,297,269	$ 101,297,269	$ 0	37
38	Total Amortization		4,347,901		80,000	80,000	0	38
39	Total Depreciation and Amortization		$ 3,884,040,042		$ 101,377,269	$ 101,377,269	$ 0	39
							Sch C-2, Sh 2, Col (d)	

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
DEPRECIATION AND ANNUALIZATION EXPENSE AT NEW RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
ADJUSTMENT NO. 13

Line No.	Description	Account Number	Gas Plant as Adjusted at 1/31/2019	Depreciation/ Amortization New Rates	Adjusted Depreciation/ Amortization	Annualized Depreciation/ Amortization	Adjustment before Alloc. to AZ	Adjustment after Alloc. to AZ	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
			WP B-2, Sh 5, Col (e)	Company Records	(c) * (d)	Sch C-2, Adj. 13, Sh 1 Col(e)	(e) - (f)	(g) * Ln 23(c)	
	Intangible Plant								
1	Organization	301	$ 61,816	N/A	$ 0	$ 0	$ 0	$ 0	1
2	Miscellaneous Intangible	303	266,767,655	Amortized	18,216,545	18,216,545	0	0	2
3	Total Intangible Plant		$ 266,829,471		$ 18,216,545	$ 18,216,545	$ 0	$ 0	3
	General Plant								
4	Land and Land Rights	389	$ 6,223,947	N/A	$ 0	$ 0	$ 0	$ 0	4
5	Structures and Improv - Co. Owned	390.1	53,818,778	2.25%	1,210,923	1,237,832	(26,909)	(14,983)	5
6	Structures and Improv - Leasehold	390.2	4,354,821	12.31%	536,078	536,078	0	0	6
7	Office Furniture and Fixtures	391	9,353,663	6.67%	623,889	623,889	0	0	7
8	Computer Software and Hardware	391.1	21,779,871	19.80%	4,312,414	4,355,974	(43,560)	(24,253)	8
9	Transportation Equipment - Light	392.11	2,907,447	10.13%	294,524	301,502	(6,978)	(3,885)	9
10	Transportation Equipment - Heavy	392.12	0	6.00%	0	0	0	0	10
11	Transportation Equipment - Aircraft	392.21	8,221,361	4.00%	328,854	328,854	0	0	11
12	Stores Equipment	393	63,037	6.67%	4,205	4,205	0	0	12
13	Tool, Shop, and Garage Equip.	394	1,106,311	6.67%	73,791	73,791	0	0	13
14	Laboratory Equipment	395	1,262,929	5.00%	63,146	63,146	0	0	14
15	Power-Operated Equipment	396	11,760	5.67%	667	666	1	1	15
16	Communication Equipment	397	7,468,337	6.67%	498,138	498,138	0	0	16
17	Telemetry Equipment	397.2	2,241	16.67%	374	373	0	0	17
18	Miscellaneous Equipment	398	3,021,779	6.67%	201,553	201,553	0	0	18
19	Total General Plant		$ 119,596,281		$ 8,148,557	$ 8,226,002	$ (77,446)	$ (43,120)	19
20	Total Depreciation		$ 115,241,460		$ 7,612,478	$ 7,689,924	$ (77,446)	$ (43,120)	20
21	Total Amortization		271,184,292		18,752,623	18,752,623	0	0	21
22	Total Depreciation and Amortization		$ 386,425,753		$ 26,365,101	$ 26,442,547	$ (77,446)	$ (43,120)	22
								Sch C-2, Sh 2, Col (d)	
23	AZ 4-Factor		55.68%						23

SOUTHWEST GAS CORPORATION
ARIZONA
TAXES OTHER THAN INCOME ADJUSTMENT
ADJUSTMENT NO. 14

Line No.	Description (a)	Reference (b)		Amount (c)	Line No.
1	Adjusted Net Plant in Service	Sch B-2, Sh 1, Ln 11(e)	$	2,467,586,189	1
2	Add: Materials and Supplies	Sch B-5, Sh 3, Ln 16(f)		34,013,908	2
3	Less: Transportation Equipment	[1]		(24,859,419)	3
4	Less: Land Rights	[2]		(17,618,322)	4
5	Estimated Full Cash Value	Sum Lns 1-4	$	2,459,122,354	5
6	2019 Assessment Ratio	Company Records		18.00%	6
7	Assessed Value	Ln 5 * Ln 6	$	442,642,024	7
8	Composite Property Tax Rate	Company Records		13.66%	8
9	Annualized Property Taxes	Ln 7 * Ln 8	$	60,467,556	9
10	Capitalized Property Taxes	Company Records		(2,834,330)	10
11	Annualized Property Tax Expense after Cap.	Ln 9 + Ln 10	$	57,633,226	11
12	Add: Salt River Tribe Assessment	Company Records		34,258	12
13	Adjusted Annualized Property Tax Expense	Ln 11 + Ln 12	$	57,667,484	13
14	Recorded Property Tax Expense	Sch C-1, Sh 15, Ln 1(c)		41,737,847	14
15	Adjustment	Ln 13 - Ln 14	$	15,929,637	15
16	Recorded Miscellaneous Taxes	Company Records	$	57,889	16
17	Adjusted Miscellaneous Taxes	Company Records		39,663	17
18	Adjustment	Ln 17 - Ln 16	$	(18,226)	18
19	Total Taxes Other Than Income Adjustment	Ln 15 + Ln 18	$	15,911,411	19
				Sch C-2, Sh 2, Col (e)	

Explanation:
To annualize Property Tax Expense to reflect adjusted investment requested in this GRC and to adjust misc. taxes to remove items expensed during the test year that should not be collected through base rates.

[1] Adjusted balance of Accounts 392.11 and 392.12 net of accumulated depreciation.
[2] Adjusted balance of Accounts 374.1 and 389.

SOUTHWEST GAS CORPORATION
ARIZONA
INTEREST ON CUSTOMER DEPOSITS
ADJUSTMENT NO. 15

Line No.	Description (a)	Reference (b)		Amount (c)	Line No.
1	Customer Deposits in Rate Base	Sch B-6, Sh 1, Ln 16(c)	$	36,862,844	1
2	Customer Deposits Interest Rate	US Treasury 1Y CMT at 1/2/19		2.60%	2
3	Adjusted Interest on Customer Deposits	Ln 1 * Ln 2	$	958,434	3
4	Recorded Interest on Customer Deposits	Company Records		2,180,878	4
5	Adjustment	Ln 3 - Ln 4	$	(1,222,444)	5
				Sch C-2, Sh 2, Col (f)	

Explanation:
The Company is proposing to modify Rule 3 to have customer deposit interest rate be more in line with other Arizona utilities and to update it annually.
This adjustment also synchronizes interest on customer deposits expense with the balance of customer deposits included as a rate base reduction.

SOUTHWEST GAS CORPORATION
ARIZONA
REGULATORY AMORTIZATIONS AND ACQUISITION ADJUSTMENT
ADJUSTMENT NO. 16

Line No.	Description (a)	Reference (b)	Account Number (c)	Amount (d)	Line No.
1	Recorded Regulatory Amortization	Company Records	407.3	$ 6,822,585	1
	Add Items To Be Amortized				
2	Property Tax Mechanism	WP C-2, Adj. 16, Sh 1		$ (2,249,147)	2
3	Tax Reform Surcredit	WP C-2, Adj. 16, Sh 1		(609,234)	3
4	Demand Side Management (DSM) Surcharge Overcollection	WP C-2, Adj. 16, Sh 1		(567,751)	4
5	Subtotal New Amortizations	Sum Lns 2-4		$ (3,426,132)	5
	Remove Test Year Expense Collected Through a Surcharge				
6	TRIMP/DOT	Company Records		$ (1,960,518)	6
7	DSM	Company Records		(4,862,067)	7
8	Subtotal Items to be Removed	Ln 6 + Ln 7	407.3	$ (6,822,585)	8
9	Adjustment	Ln 5 + Ln 8	407.3	$ (10,248,717) Sch C-2, Sh 2, Col (g)	9
10	Adjusted Regulatory Amortizations	Ln 1 + Ln 9	407.3	$ (3,426,132)	10
11	Reamortize Ajo Acquisition Amortization	WP C-2, Adj. 16, Sh 1	406	$ 49,800 Sch C-2, Sh 2, Col (g)	11

Explanation:
To adjust regulatory amortizations by removing the portion of expense related to surcharges since the offsetting revenues are not included in revenue at present rates, add new regulatory amortizations. Also reamortizes an acquisition adjustment that would have otherwise expired in 2020.

SOUTHWEST GAS CORPORATION
ARIZONA
COMPUTATION OF GROSS REVENUE CONVERSION FACTOR

Line No.	Description (a)	Reference (b)		Amount (c)	Line No.
1	Gross Operating Revenues		$	1,000.00	1
2	Less: Uncollectibles	Sch C-2, Adj. 7, Sh 1		0.1930%	2
3	Subtotal	Ln 1 * (1 - Ln 2)	$	998.07	3
4	Less: State Income Tax	Sch C-3, Sh 2, Ln 1(c)		4.9000%	4
5	Subtotal	Ln 3 * (1 - Ln 4)	$	949.16	5
6	Less: Federal Income Tax	Sch C-3, Sh 2, Ln 3(c)		19.9710%	6
7	Total	Ln 5 - (Ln 3 * Ln 6)	$	749.84	7
8	Gross Revenue Conversion Factor	Ln 1 / Ln 7		1.3336	8
				Sch A-1, Sh 1, Ln 7(e)	

SOUTHWEST GAS CORPORATION
ARIZONA
COMPUTATION OF STATE AND FEDERAL INCOME TAX RATES

Line No.	Description (a)	Reference (b)	Amount (c)	Line No.
1	State Income Tax Rate	Current Statutory Rate	4.9000% Sch C-1, Sh 16, Ln 6	1
2	Federal Income Tax Rate	Current Statutory Rate	21.0000%	2
3	Effective Federal Income Tax Rate	Ln 2 * (1 - Ln 1)	19.9710% Sch C-1, Sh 16, Ln 13	3
4	Total Effective Income Tax Rate	Ln 1 + Ln 3	24.8710%	4

SCHEDULE D

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF CAPITAL AT JANUARY 31, 2019

ORIGINAL COST RATE BASE (OCRB) COST OF CAPITAL

Line No.	Description	Capital Ratio	Capital Cost		Weighted Cost of Capital	Line No.
	(a)	(b)	(c)		(d)	
1	Long-Term Debt	48.90%	4.86%	[1]	2.38%	1
2	Common Equity	51.10%	10.30%	[2]	5.26%	2
3	Total	100.00%			7.64%	3

[1] Reference Schedule D-2, Sheet 1 of 6
[2] Reference Schedule D-4, Sheet 1 of 1

FAIR VALUE RATE OF RETURN [3]

Line No.	Description	Capital Ratio	Capital Cost		Weighted Cost of Capital	Line No.
	(a)	(b)	(c)		(d)	
1	Long-Term Debt	37.27%	4.86%	[1]	1.81%	1
2	Common Equity	38.95%	10.30%	[2]	4.01%	2
3	FVRB Increment Above OCRB	23.78%	0.66%	[2]	0.16%	3
4	Total	100.00%			5.98%	4

[1] Reference Schedule D-2, Sheet 1 of 6
[2] Reference Schedule D-4, Sheet 1 of 1
[3] FVROR is based on FVRB/OCRB = 1.31

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
NET CAPITAL AT JANUARY 31, 2019

Line No.	Description (a)	Net System Balance at 01/31/2019 (b)	Adjustments (c)	Pro Forma Net Capital Amounts (d)	Capital Ratio (e)	Line No.
	Debt					
	Long-Term Debt:					
1	Debentures & Medium Term Notes	$ 1,454,395,239	$ -	$ 1,454,395,239	39.50%	1
2	Term Facilities	149,456,269	-	149,456,269	4.06%	2
3	Clark County IDRB's	146,868,038		146,868,038	3.99%	3
4	Big Bear IDRB's	49,580,440		49,580,440	1.35%	4
5	Total Long-Term Debt	$ 1,800,299,986	$ -	$ 1,800,299,986	48.90%	5
	Equity					
6	Preferred Equity	$ -	-	$ -	0.00%	6
7	Common Equity	1,881,310,331	-	1,881,310,331	51.10%	7
8	Total Equity	$ 1,881,310,331	$ -	$ 1,881,310,331	51.10%	8
9	Total Capital	$ 3,681,610,317	$ -	$ 3,681,610,317	100.00%	9

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
PROJECTED COST OF CAPITAL AT JANUARY 31, 2020

ORIGINAL COST RATE BASE (OCRB) COST OF CAPITAL

Line No.	Description	Capital Ratio	Capital Cost		Weighted Cost of Capital	Line No.
	(a)	(b)	(c)		(d)	
1	Long-Term Debt	49.77%	4.80%	[1]	2.39%	1
2	Common Equity	50.23%	10.30%	[2]	5.17%	2
3	Total	100.00%			7.56%	3

[1] Reference Schedule D-2, Sheet 4 of 6
[2] Reference Schedule D-4, Sheet 1 of 1

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
PROJECTED NET CAPITAL AT JANUARY 31, 2020

Line No.	Description	Net System Balance at 01/31/2020	Adjustments	Pro Forma Net Capital Amounts	Capital Ratio	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Debt					
	Long-Term Debt:					
1	Debentures & Medium Term Notes	$ 1,755,770,010	$ -	$ 1,755,770,010	41.58%	1
2	Term Facilities	149,456,269	-	149,456,269	3.54%	2
3	Clark County IDRB's	146,693,012		146,693,012	3.47%	3
4	Big Bear IDRB's	49,580,440		49,580,440	1.17%	4
5	Total Long-Term Debt	$ 2,101,499,731	$ -	$ 2,101,499,731	49.77%	5
	Equity					
6	Preferred Equity	$ -	-	$ -	0.00%	6
7	Common Equity	2,120,630,331	-	2,120,630,331	50.23%	7
8	Total Equity	$ 2,120,630,331	$ -	$ 2,120,630,331	50.23%	8
9	Total Capital	$ 4,222,130,062	$ -	$ 4,222,130,062	100.00%	9

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF DEBT AT JANUARY 31, 2019

Line No.	Description	Net Principal Amount Outstanding	Interest Rate	Cost of Debt	Line No.
	(a)	(b)	(c)	(d)	
1	Fixed Rate Debt [1]	$ 1,454,395,239	5.00%	$ 72,741,085	1
2	Variable Rate Debt [2]	149,456,269	3.50%	5,229,641	2
3	Total Long-Term Debt	$ 1,603,851,508	4.86%	$ 77,970,726	3

[1] Reference Schedule D-2, Sheet 2 of 6
[2] Reference Schedule D-2, Sheet 3 of 6

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF LONG-TERM FIXED RATE DEBT
AT JANUARY 31, 2019

Line No.	Description (a)	Principal Amount Outstanding (b)	Unamortized Debt Expense and Discount (c)	Net Proceeds (d)	Effective Interest Rate (e)	Cost of Debt (f)
	Debentures					
1	4.45% Notes, Due 2020	$ 125,000,000	$ 2,506,456	$ 122,493,544	5.65%	$ 6,920,413
2	3.875% Notes, Due 2022	250,000,000	7,669,286	242,330,714	4.99%	12,089,373
3	8.0% Debenture, Due 2026	75,000,000	3,590,921	71,409,079	8.89%	6,346,993
4	3.70% Notes, Due 2028	300,000,000	3,109,006	296,890,994	3.84%	11,400,614
5	6.1% Notes, Due 2043	125,000,000	146,995	124,853,005	6.11%	7,628,256
6	4.875% Notes, Due 2022	250,000,000	2,545,774	247,454,226	4.95%	12,241,369
7	3.80% Notes, Due 2046	300,000,000	4,119,774	295,880,226	3.88%	11,484,313
8	Total Debentures	$ 1,425,000,000	$ 23,688,212	$ 1,401,311,788	4.86%	$ 68,111,331
	Medium Term Notes					
9	7.78% MTN, Due 2022	$ 25,000,000	$ 53,539	$ 24,946,461	7.86%	$ 1,960,792
10	7.92% MTN, Due 2027	25,000,000	123,753	24,876,247	8.00%	1,990,100
11	6.76% MTN, Due 2027	7,500,000	-	7,500,000	6.76%	507,000
12	Total Medium Term Notes	$ 57,500,000	$ 177,292	$ 57,322,708	7.78%	$ 4,457,892
13	Unamortized Loss on Reacquired Debt[1]	$ -	$ 4,239,257	$ (4,239,257)	-4.05%	$ 171,862
14	Total Debentures and MTNs	$ 1,482,500,000	$ 28,104,761	$ 1,454,395,239	5.00%	$ 72,741,085
					Sch D-2, Sheet 1	
	Tax Exempt Clark County					
	Amortization of Loss/(Gain) from:					
15	1999 Clark County, Series A	$ -	$ 371,250	$ (371,250)	-5.04%	$ 18,718
16	1999 Clark County, Series C	-	506,055	(506,055)	-5.04%	25,515
17	1999 Clark County, Series D	-	292,913	(292,913)	-5.04%	14,769
18	2003 Clark County, Series C	-	939,474	(939,474)	-5.24%	49,230
19	2003 Clark County, Series D	-	1,121,466	(1,121,466)	-5.24%	58,767
20	2003 Clark County, Series E	-	148,132	(148,132)	-5.24%	7,762
21	2004 Clark County, Series A	-	924,268	(924,268)	-6.49%	59,952
22	2004 Clark County, Series B	-	(3,333,576)	3,333,576	-6.74%	(224,736)
23	2005 Series A, Due 2034		994,115	(994,115)	-6.00%	59,647
24	2006 Clark County, Series A	-	(4,301,833)	4,301,833	-5.69%	(244,654)
25	Total Amortization of Loss/ (Gain) from retirement of Industrial Revenue Bonds	$ -	$ (2,337,736)	$ 2,337,736	-7.49%	$ (175,030)
26	Total Fixed-Rate Debt	$ 1,482,500,000	$ 25,767,025	$ 1,456,732,975	4.98%	$ 72,566,055

[1] In March 2010, the Company redeemed the $100 million, 7.70% Subordinated Debentures (Trust Originated Preferred Securities), due 9/15/2043, at par. The unamortized debt expenses were recorded as a reacquisition loss and will be amortized over the remaining life of the retired securities.

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
VARIABLE RATE DEBT COST OF DEBT
AT JANUARY 31, 2019

Line No.	Description (a)	Principal Amount Outstanding (b)	Unamortized Debt Expense and Discount (c)	Net Proceeds (d)	Interest Rate (e)	Cost of Debt (f)	Line No.
1	Term Facility[1]	$ 150,000,000	$ 543,731	$ 149,456,269	3.50% Sch D-2, Sheet 1	$ 5,229,641	1
2	Big Bear 1993 Series A IDRB	$ 50,000,000	$ 419,560	$ 49,580,440	2.46%	$ 1,218,228	2
3	Clark Co.2003 Series A IDRB	$ 50,000,000	$ 1,667,352	$ 48,332,648	2.57%	1,242,224	3
4	Clark Co.2008 Series A IDRB	50,000,000	3,257,880	46,742,120	2.75%	1,284,778	4
5	Clark Co.2009 Series A IDRB	50,000,000	544,466	49,455,534	2.18%	1,076,631	5
6	Total Clark Co. Tax Exempt	$ 150,000,000	$ 5,469,698	$ 144,530,302	2.49%	$ 3,603,633	6

[1] Based on $150 million designated long-term of the $400 million Bank Facility

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
PROJECTED COST OF DEBT AT JANUARY 31, 2020

Line No.	Description	Net Principal Amount Outstanding	Interest Rate	Cost of Debt	Line No.
	(a)	(b)	(c)	(d)	
1	Fixed Rate Debt [1]	$ 1,454,395,239	4.91%	$ 71,372,640	1
2	Variable Rate Debt [2]	149,456,269	3.75%	5,603,282	2
3	Total Long-Term Debt	$ 1,603,851,508	4.80%	$ 76,975,922	3

[1] Reference Schedule D-2, Sheet 5 of 6
[2] Reference Schedule D-2, Sheet 6 of 6

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
PROJECTED COST OF LONG-TERM FIXED RATE DEBT
AT JANUARY 31, 2020

Line No.	Description (a)	Principal Amount Outstanding (b)	Unamortized Debt Expense and Discount (c)	Net Proceeds (d)	Effective Interest Rate (e)	Cost of Debt (f)	Line No.
	Debentures						
1	4.45% Notes, Due 2020	$ 125,000,000	$ 1,143,899	$ 123,856,101	5.60%	$ 6,932,226	1
2	3.875% Notes, Due 2022	250,000,000	5,260,618	244,739,382	4.94%	12,099,915	2
3	8.0% Debenture, Due 2026	75,000,000	3,236,218	71,763,782	8.89%	6,378,520	3
4	3.70% Notes, Due 2028	300,000,000	2,819,981	297,180,019	3.84%	11,411,713	4
5	6.1% Notes, Due 2043	125,000,000	143,690	124,856,310	6.11%	7,628,458	5
6	4.875% Notes, Due 2022	250,000,000	2,490,239	247,509,761	4.95%	12,244,116	6
7	3.80% Notes, Due 2046	300,000,000	4,034,643	295,965,357	3.88%	11,487,617	7
8	4.43% Notes, Due 2049[1]	300,000,000	3,383,383	296,616,617	4.50%	13,347,748	8
9	Total Debentures	$ 1,725,000,000	$ 22,512,671	$ 1,702,487,329	4.79%	$ 81,530,313	9
	Medium Term Notes						
10	7.78% MTN, Due 2022	$ 25,000,000	$ 37,109	$ 24,962,891	7.86%	$ 1,962,083	10
11	7.92% MTN, Due 2027	25,000,000	112,815	24,887,185	8.00%	1,990,975	11
12	6.76% MTN, Due 2027	7,500,000	-	7,500,000	6.76%	507,000	12
13	Total Medium Term Notes	$ 57,500,000	$ 149,924	$ 57,350,076	7.78%	$ 4,460,058	13
	Unamortized Loss on						
14	Reacquired Debt[2]	$ -	$ 4,067,395	$ (4,067,395)	-4.23%	$ 171,862	14
15	Total Debentures and MTNs	$ 1,782,500,000	$ 26,729,990	$ 1,755,770,010	4.91%	$ 86,162,233	15
					Sch D-2, Sheet 4		
	Tax Exempt Clark County						
	Amortization of Loss/(Gain) from:						
16	1999 Clark County, Series A	$ -	$ 352,531	$ (352,531)	-5.31%	$ 18,718	16
17	1999 Clark County, Series C	-	480,539	(480,539)	-5.31%	25,515	17
18	1999 Clark County, Series D	-	278,144	(278,144)	-5.31%	14,769	18
19	2003 Clark County, Series C	-	890,244	(890,244)	-5.53%	49,230	19
20	2003 Clark County, Series D	-	1,062,699	(1,062,699)	-5.53%	58,767	20
21	2003 Clark County, Series E	-	140,370	(140,370)	-5.53%	7,762	21
22	2004 Clark County, Series A	-	864,315	(864,315)	-6.94%	59,952	22
23	2004 Clark County, Series B	-	(3,108,841)	3,108,841	-7.23%	(224,736)	23
24	2005 Series A, Due 2034		934,468	(934,468)	-6.38%	59,647	24
25	2006 Clark County, Series A	-	(4,057,179)	4,057,179	-6.03%	(244,654)	25
26	Total Amortization of Loss/ (Gain) from retirement of Industrial Revenue Bonds	$ -	$ (2,162,710)	$ 2,162,710	-8.09%	$ (175,030)	26
27	Total Fixed-Rate Debt	$ 1,782,500,000	$ 24,567,280	$ 1,757,932,720	4.89%	$ 85,987,203	27

[1] Projected issuance
[2] In March 2010, the Company redeemed the $100 million, 7.70% Subordinated Debentures (Trust Originated Preferred Securities), due 9/15/2043, at par. The unamortized debt expenses were recorded as a reacquisition loss and will be amortized over the remaining life of the retired securities.

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
PROJECTED VARIABLE RATE DEBT COST OF DEBT
AT JANUARY 31, 2020

Line No.	Description (a)	Principal Amount Outstanding (b)	Unamortized Debt Expense and Discount (c)	Net Proceeds (d)	Interest Rate (e)	Cost of Debt (f)	Line No.
1	Term Facility[1]	$ 150,000,000	$ 289,369	$ 149,456,269	3.75%	$ 5,603,282	1
					Sch D-2, Sheet 4		
2	Big Bear 1993 Series A IDRB	$ 50,000,000	$ 338,594	$ 49,580,440	2.63%	$ 1,304,994	2
3	Clark Co.2003 Series A IDRB	$ 50,000,000	$ 1,535,273	$ 48,332,648	2.75%	1,326,806	3
4	Clark Co.2008 Series A IDRB	50,000,000	3,066,948	46,742,120	2.92%	1,366,577	4
5	Clark Co.2009 Series A IDRB	50,000,000	496,681	49,455,534	2.35%	1,163,178	5
6	Total Clark Co. Tax Exempt	$ 150,000,000	$ 5,098,903	$ 144,530,302	2.67%	$ 3,856,561	6

[1] Based on $150 million designated long-term of the $400 million Bank Facility

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF PREFERRED SECURITIES[1]
AT JANUARY 31, 2019

Line No.	Description (a)	Net Proceeds Per Security (b)	Number of Securities (c)	Net Proceeds (d)	Effective Cost (e)	Annual Cost (f)	Line No.

[1] The Company has no outstanding preferred securities

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
PROJECTED COST OF PREFERRED SECURITIES[1]
AT JANUARY 31, 2020

Line No.	Description	Net Proceeds Per Security	Number of Securities	Net Proceeds	Effective Cost	Annual Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	

[1] The Company has no outstanding preferred securities and has no plan to issue preferred securities

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF COMMON EQUITY

Line No.	Description (a)	Line No.
1	The cost of common equity requested is 10.30% [1]	1

[1] Prepared Direct Testimony of Southwest Gas witness Robert B. Hevert

SCHEDULE E

SOUTHWEST GAS CORPORATION
COMPARATIVE BALANCE SHEETS [1]

Line No.	Description	Balance at 01/31/2019 Arizona	Other	Total	Balance at 12/31/2018 Arizona	Other	Total	Balance at 12/31/2017 Arizona	Other	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
		Company Records	(d) - (b)	Company Records	Company Records	(g) - (e)	Company Records	Company Records	(j) - (h)	Company Records	
	Assets and Other Debits										
	Utility Plant										
1	Utility Plant (101, 105, 114, 118)	$ 3,477,953,285	$ 3,339,204,260	$ 6,817,157,545	$ 3,445,717,122	$ 3,320,561,635	$ 6,766,278,757	$ 3,176,594,076	$ 3,102,369,135	$ 6,278,963,211	1
2	Completed Construction Not Classified (106)	226,564,390	109,118,617	335,683,008	241,537,359	115,032,259	356,569,618	210,830,632	128,459,236	339,289,868	2
3	Construction Work in Progress (107)	118,183,026	64,784,951	182,967,978	127,716,234	65,311,981	193,028,215	73,311,572	51,930,649	125,242,221	3
4	Total Utility Plant	$ 3,822,700,701	$ 3,513,107,829	$ 7,335,808,530	$ 3,814,970,715	$ 3,500,905,875	$ 7,315,876,590	$ 3,460,736,280	$ 3,282,759,020	$ 6,743,495,300	4
	Less: Accumulated Provision for Depreciation										
5	and Amortization (108, 111 119)	1,405,620,040	1,210,064,430	2,615,684,470	1,401,966,273	1,203,672,037	2,605,638,311	1,387,804,914	1,147,046,687	2,534,851,601	5
6	Net Utility Plant	$ 2,417,080,661	$ 2,303,043,399	$ 4,720,124,060	$ 2,413,004,441	$ 2,297,233,838	$ 4,710,238,280	$ 2,072,931,366	$ 2,135,712,333	$ 4,208,643,699	6
	Other Property and Investments										
7	Northern California Surcharge (120)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	7
8	Non-Utility Property (121)	0	201,337	201,337	0	201,337	201,337	0	201,337	201,337	8
9	Non-Utility Accumulated Depreciation (122)	0	0	0	0	0	0	0	0	0	9
	Investment in Subsidiary and Associated										
10	Companies (123, 123.1)	0	120,784,478	120,784,478	0	119,103,531	119,103,531	0	1,390,302,235	1,390,302,235	10
11	Other Investments (124)	0	0	0	0	0	0	0	0	0	11
12	Special Funds (125,128)	0	114,416,674	114,416,674	0	114,404,719	114,404,719	0	117,340,673	117,340,673	12
13	Total Other Property and Investments	$ 0	$ 235,402,490	$ 235,402,490	$ 0	$ 233,709,587	$ 233,709,587	$ 0	$ 1,507,844,246	$ 1,507,844,246	13
	Current and Accrued Assets										
14	Cash (131)	$ 0	$ 16,712,336	$ 16,712,336	$ 0	$ (12,999,141)	$ (12,999,141)	$ 0	$ (6,806,507)	$ (6,806,507)	14
15	Working Funds (135)	0	789,887	789,887	0	535,941	535,941	0	548,918	548,918	15
16	Temporary Cash Investments (136)	0	4,068,672	4,068,672	0	18,080,913	18,080,913	0	22,224,867	22,224,867	16
	Notes and Accounts Receivables Less Accumulated										
17	Provision for Uncollectible Accounts (141-144)	9,520,976	157,985,923	167,506,900	9,826,094	130,478,163	140,304,257	9,234,792	111,323,610	120,558,402	17
18	Receivables from Associated Companies (145-146)	0	21,016,444	21,016,444	0	20,713,932	20,713,932	0	35,964,580	35,964,580	18
19	Materials and Supplies (151,154, 155, 163)	40,196,044	17,724,057	57,920,101	38,517,947	17,634,510	56,152,456	21,526,670	11,719,176	33,245,846	19
20	Liquefied Natural Gas Stored (164.1, 164.2)	1,934,798	7,037,478	8,972,276	2,161,318	7,886,756	10,048,073	2,144,795	8,419,915	10,564,710	20
21	Prepayments (165)	0	17,714,903	17,714,903	0	17,047,190	17,047,190	0	15,655,061	15,655,061	21
22	Interest and Dividends Receivable (171)	0	0	0	0	0	0	0	0	0	22
23	Accrued Utility Revenue (173)	0	68,800,000	68,800,000	0	77,200,000	77,200,000	0	78,200,000	78,200,000	23
24	Miscellaneous Current and Accrued Assets (174)	0	4,931,026	4,931,026	0	7,666,366	7,666,366	0	(2,051,808)	(2,051,808)	24
25	Total Current and Accrued Assets	$ 51,651,819	$ 316,780,726	$ 368,432,545	$ 50,505,359	$ 284,244,629	$ 334,749,988	$ 32,906,257	$ 275,197,811	$ 308,104,067	25
	Deferred Debits										
26	Unamortized Debt Discount and Expenses (181)	$ 0	$ 8,675,984	$ 8,675,984	$ 0	$ 8,741,570	$ 8,741,570	$ 0	$ 6,941,213	$ 6,941,213	26
27	Other Regulatory Assets (182)	81,972,066	406,975,333	488,947,400	86,036,469	431,502,901	517,539,370	54,214,448	410,243,576	464,458,024	27
28	Preliminary Survey and Investigative Charges (183)	0	2,084,879	2,084,879	0	2,084,879	2,084,879	0	867,390	867,390	28
29	Clearing Accounts (184)	99,036	653,415	752,451	68,309	565,998	634,307	61,224	121,249	182,474	29
30	Miscellaneous Deferred Debits (186)	6,056,927	5,857,357	11,914,285	5,829,973	5,406,682	11,236,656	5,787,946	5,375,771	11,163,717	30
31	Research and Development (188)	0	0	0	0	0	0	0	0	0	31
32	Loss on Reacquired Debt (189)	0	19,488,857	19,488,857	0	19,599,333	19,599,333	0	20,913,382	20,913,382	32
33	Accumulated Deferred Income Taxes (190)	0	22,573,720	22,573,720	0	22,573,720	22,573,720	0	5,459,713	5,459,713	33
34	Unrecovered Purchased Gas Costs (191)	(69,697,749)	22,641,690	(47,056,059)	(72,878,319)	(1,955,670)	(74,833,989)	5,068,683	2,671,493	7,740,176	34
35	Total Deferred Debits	$ 18,430,280	$ 488,951,234	$ 507,381,515	$ 19,056,432	$ 488,519,413	$ 507,575,845	$ 65,132,302	$ 452,593,786	$ 517,726,089	35
36	Total Assets and Other Debits	$ 2,487,162,760	$ 3,344,177,849	$ 5,831,340,609	$ 2,482,566,232	$ 3,303,707,467	$ 5,786,273,699	$ 2,170,969,925	$ 4,371,348,176	$ 6,542,318,101	36

NOTE: The Arizona columns above reflect only those amounts separately identified in the Southwest Gas general ledger as pertaining solely to Arizona. Allocations are not included, thus the debits and credits in the Arizona columns do not balance. The financial statements appearing herein are unaudited, and were prepared solely for the purposes of complying with the filing requirements for this general rate case.

[1] Includes Southwest Gas Holdings

SOUTHWEST GAS CORPORATION
COMPARATIVE BALANCE SHEETS [1]

Line No.	Description	Balance at 01/31/2019			Balance at 12/31/2018			Balance at 12/31/2017			Line No.
		Arizona	Other	Total	Arizona	Other	Total	Arizona	Other	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
		Company Records	(d) - (b)	Company Records	Company Records	(g) - (e)	Company Records	Company Records	(j) - (h)	Company Records	
	Liabilities and Other Credits										
	Proprietary Capital										
1	Common Stock Issued (201)	$ 0	$ 49,111,954	$ 49,111,954	$ 0	$ 49,111,954	$ 49,111,954	$ 0	$ 98,832,310	$ 98,832,310	1
2	Preferred Stock Issued (204)	0	0	0	0	0	0	0	0	0	2
3	Premium on Capital Stock (207)	0	1,090,389,677	1,090,389,677	0	1,091,820,314	1,091,820,314	0	1,921,609,618	1,921,609,618	3
4	Other Paid in Capital (208-211)	0	0	0	0	0	0	0	0	0	4
5	Reacquired Capital Stock (217)	0	0	0	0	0	0	0	0	0	5
6	Capital Stock Expense (214)	0	(11,333,051)	(11,333,051)	0	(11,333,051)	(11,333,051)	0	(23,287,812)	(23,287,812)	6
7	Retained Earnings (216)	0	819,751,614	819,751,614	0	761,425,343	761,425,343	0	827,147,512	827,147,512	7
8	Total Proprietary Capital	$ 0	$ 1,947,920,194	$ 1,947,920,194	$ 0	$ 1,891,024,559	$ 1,891,024,559	$ 0	$ 2,824,301,628	$ 2,824,301,628	8
	Long-Term Debt										
9	Bonds and Swaps (219, 221, 222)	$ 0	$ 1,633,662,612	$ 1,633,662,612	$ 0	$ 1,633,450,794	$ 1,633,450,794	$ 0	$ 1,335,426,714	$ 1,335,426,714	9
10	Other Long-Term Debt (223, 224, 226)	0	144,598,882	144,598,882	0	144,556,923	144,556,923	0	159,878,852	159,878,852	10
11	Other Preferred Securities (224.1)	0	0	0	0	0	0	0	0	0	11
12	Total Long-Term Debt	$ 0	$ 1,778,261,494	$ 1,778,261,494	$ 0	$ 1,778,007,717	$ 1,778,007,717	$ 0	$ 1,495,305,567	$ 1,495,305,567	12
	Current and Accrued Liabilities										
13	Notes Payable (231)	$ 0	$ 169,000,000	$ 169,000,000	$ 0	$ 152,000,000	$ 152,000,000	$ 0	$ 214,500,000	$ 214,500,000	13
14	Accounts Payable (232)	0	136,899,009	136,899,009	0	158,666,315	158,666,315	0	135,251,560	135,251,560	14
15	Payables to Associated Companies (233, 234)	0	21,369,981	21,369,981	0	21,342,534	21,342,534	0	14,884,225	14,884,225	15
16	Customer Deposits (235)	36,495,586	31,779,530	68,275,116	36,256,300	31,683,420	67,939,720	37,444,662	32,336,022	69,780,684	16
17	Taxes Accrued (236)	23,693,634	1,686,596	25,380,230	18,903,121	(5,197,709)	13,705,412	19,668,256	12,170,731	31,838,987	17
18	Interest Accrued (237)	1,149,019	24,766,380	25,915,399	1,138,453	19,104,446	20,242,899	1,190,476	15,985,326	17,175,802	18
19	Dividends Declared (238)	0	23,500,000	23,500,000	0	23,500,000	23,500,000	0	44,804,759	44,804,759	19
20	Tax Collections Payable (241)	13,839,961	5,887,730	19,727,691	11,090,842	6,275,212	17,366,054	9,388,223	8,589,957	17,978,180	20
21	Miscellaneous Current and Accrued Liabilities (242)	1,484,762	(28,537,574)	(27,052,812)	(6,303,393)	9,425,071	3,121,679	(6,034,056)	5,061,723	(972,333)	21
22	Obligations Under Capital Leases (243)	0	580,886	580,886	0	0	0	0	0	0	22
23	Total Current and Accrued Liabilities	$ 76,662,962	$ 386,351,653	$ 463,595,500	$ 61,085,323	$ 416,799,291	$ 477,884,614	$ 61,657,561	$ 483,584,303	$ 545,241,864	23
	Deferred Credits										
24	Customer Advances for Construction (252)	$ 44,361,607	$ 47,968,849	$ 92,330,457	$ 44,443,844	$ 47,510,476	$ 91,954,321	$ 37,844,181	$ 42,000,629	$ 79,844,810	24
25	Other Deferred Credits (253)	0	503,865,408	503,865,408	0	503,859,627	503,859,627	0	521,219,428	521,219,428	25
26	Other Regulatory Liabilities (254)	1,514,787	458,948,132	460,462,919	1,890,123	458,772,074	460,662,197	72,463	433,669,533	433,741,996	26
27	Accumulated Deferred Investment Tax Credit (255)	177,671	169,715	347,387	193,823	174,033	367,856	661,547	319,543	981,090	27
28	Unamortized Gain on Reacquired Debt (257)	0	8,672,096	8,672,096	0	8,716,780	8,716,780	0	9,252,982	9,252,982	28
29	Accumulated Deferred Income Taxes (282, 283)	339,713,050	178,015,477	517,728,527	339,965,949	171,463,809	511,429,758	310,804,516	136,961,832	447,766,348	29
30	Total Deferred Credits	$ 385,767,115	$ 1,197,639,678	$ 1,583,406,793	$ 386,493,739	$ 1,190,496,799	$ 1,576,990,539	$ 349,382,707	$ 1,143,423,947	$ 1,492,806,654	30
	Other Long-Term Liabilities										
31	Obligations Under Leases (227)	$ 0	$ 1,218,609	$ 1,218,609	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	
32	Injuries and Damages Reserve (228)	0	4,040,000	4,040,000	0	4,040,000	4,040,000	0	2,550,000	2,550,000	32
33	Provision for Rate Refunds (229)	0	0	0	0	0	0	0	0	0	33
34	Total Other Long-Term Liabilities	$ 0	$ 5,258,609	$ 5,258,609	$ 0	$ 4,040,000	$ 4,040,000	$ 0	$ 2,550,000	$ 2,550,000	34
35	Total Liabilities and Other Credits	$ 462,430,076	$ 5,315,431,627	$ 5,778,442,589	$ 447,579,062	$ 5,280,368,366	$ 5,727,947,428	$ 411,040,267	$ 5,949,165,444	$ 6,360,205,712	35

NOTE: The Arizona columns above reflect only those amounts separately identified in the Southwest Gas general ledger as pertaining solely to Arizona. Allocations are not included, thus the debits and credits in the Arizona columns do not balance. The financial statements appearing herein are unaudited, and were prepared solely for the purposes of complying with the filing requirements for this general rate case.

[1] Includes Southwest Gas Holdings

SOUTHWEST GAS CORPORATION
ARIZONA
COMPARATIVE INCOME STATEMENTS

Line No.	Description	Test Year Ended 1/31/2019	Year Ended 12/31/2018	Year Ended 12/31/2017	Line No.
	(a)	(b)	(c)	(d)	
		Sch E-6, Sh 1	Sch E-6, Sh 1	Sch E-6, Sh 1	
1	Operating Revenue	$ 701,861,439	$ 703,154,972	$ 698,283,506	1
2	Operating Expenses and Taxes	600,178,265	600,533,882	600,070,532	2
3	Operating Income	$ 101,683,174	$ 102,621,090	$ 98,212,974	3
4	Other Income and Deductions	0	0	0	4
5	Income Before Interest Deductions	$ 101,683,174	$ 102,621,090	$ 98,212,974	5
6	Net Interest Deductions	42,132,493	43,133,574 [1]	35,887,107 [1]	6
7	Net Income	$ 59,550,682	$ 59,487,516	$ 62,325,867	7
		Sch A-2, Sh 1	Sch A-2, Sh 1	Sch A-2, Sh 1	

[1] Source: Company Records

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
STATEMENTS OF INCOME [1]

Line No.	Description	Year Ended 1/31/2019	Year Ended 12/31/2018	Year Ended 12/31/2017	Line No.
	(a)	(b)	(c)	(d)	
	Utility Operating Income				
1	Operating Revenues (400)	$ 1,369,234,730	$ 1,357,727,493	$ 1,302,308,138	1
	Operating Expenses:				
2	Operating Expenses (401)	$ 766,494,048	$ 759,465,807	$ 681,621,732	2
3	Maintenance Expenses (402)	85,134,939	85,795,368	85,610,298	3
4	Depreciation Expense (403)	172,541,807	171,704,195	172,383,364	4
5	Amortization of Other Limited Term Gas Plant (404.3)	13,817,406	13,910,608	14,538,188	5
6	Amortization of Utility Plant Acquisition Adjustment (406)	87,398	104,634	153,886	6
7	Amortization of Property Losses (407.1)	0	0	0	7
8	Amortization of Regulatory Assets (407.3)	7,296,808	6,096,354	14,847,035	8
9	Amortization of Regulatory Liabilities (407.4)	0	0	0	9
10	Taxes Other than Income Taxes (408.1)	60,234,566	59,898,302	57,945,866	10
11	Income Taxes - Federal (409.1)	(18,082,445)	(25,679,874)	(106,587)	11
12	Income Taxes - Other (409.1)	(498,315)	(1,277,522)	1,393,084	12
13	Provision for Deferred Income Taxes (410.1)	432,964,568	439,118,985	440,307,853	13
14	Provision for Deferred Income Taxes - Credit (411.1)	(373,483,179)	(371,445,214)	(373,867,564)	14
15	Investment Tax Credit Adjustment - Net (411.4)	(582,601)	(613,234)	(729,298)	15
16	Total Operating Expenses	$ 1,145,925,001	$ 1,137,078,410	$ 1,094,097,856	16
17	Net Utility Operating Income	$ 223,309,728	$ 220,649,084	$ 208,210,282	17
	Other Income and Deductions				
	Other Income:				
18	Non-Utility Operating Income (415-418)	$ 0	$ 0	$ 0	18
19	Equity in Earnings of Subsidiary Companies (418.1)	139,758	139,538	195,295,554	19
20	Interest and Dividend Income (419)	6,664,097	6,453,645	3,497,223	20
21	Allowance for Equity Funds Used During Construction (419.1)	3,899,336	3,626,653	2,296,479	21
22	Amortization of Investment Tax Credits (420)	0	0	0	22
23	Miscellaneous Non-Operating Income (421)	682,926	348,382	654,257	23
24	Gain on Disposition of Property (421.1)	0	0	0	24
25	Total Other Income	$ 11,386,117	$ 10,568,218	$ 201,743,514	25
	Other (Income) Deductions				
26	Miscellaneous Amortizations (425)	$ 0	$ 0	$ 0	26
27	Miscellaneous (Income) Deductions (426)	6,377,330	6,342,721	(7,132,239)	27
28	Total Other (Income) Deductions	$ 6,377,330	$ 6,342,721	$ (7,132,239)	28
	Taxes Applicable to Other Income and Deductions				
29	Taxes Other than Income Taxes (408.2)	$ 11,318	$ 11,318	$ 15,017	29
30	Income Taxes (409.2)	2,726,241	2,539,958	350,748	30
31	Provision for Deferred Income Taxes (410.2, 411.2)	1,310,207	1,307,935	(4,717,126)	31
32	Investment Tax Credit Adjustment - Net (411.5)	0	0	0	32
33	Total Taxes Applicable to Other Income and Deductions	$ 4,047,766	$ 3,859,211	$ (4,351,360)	33
34	Net Other Income and (Deductions)	$ 961,021	$ 366,286	$ 213,227,113	34
	Interest Charges				
35	Interest on Long-Term Debt (427)	$ 77,607,886	$ 76,233,410	$ 64,094,580	35
36	Amortization of Debt Discount and Expense (428)	2,627,575	2,609,594	2,442,562	36
37	Amortization of Gain on Reacquired Debt (429)	(536,203)	(536,203)	(536,203)	37
38	Other Interest Expense (430-431)	7,271,358	7,130,338	6,442,787	38
39	Total Interest Charges	$ 86,970,616	$ 85,437,138	$ 72,443,727	39
40	Allowance for Borrowed Funds Used During Construction (432)	(3,420,448)	(3,263,782)	(1,666,170)	40
41	Interest and Dividends (438)	90,180,164	90,180,164	177,235,358	41
42	Net Interest Charges	$ 83,550,168	$ 172,353,521	$ 248,012,915	42
43	Net Income	$ 140,720,581	$ 48,661,850	$ 173,424,480	43

[1] Includes Southwest Gas Holdings

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
COMPARATIVE STATEMENT OF CASH FLOWS
($ THOUSANDS)

Line No.	Description (a)	Test Year Ended 01/31/2019 (b)	Year Ended 12/31/2018 (c)	Year Ended 12/31/2017 (d)	Line No.
	CASH FLOWS FROM OPERATING ACTIVITIES:				
1	Net Income	$ 140,721	$ 138,842	$ 156,818	1
2	Adjustments to reconcile net income to net cash				2
3	provided by operating activities:				3
4	Depreciation and amortization	193,743	191,816	201,922	4
5	Other Amortization	5,436	5,418	5,167	5
6	Change in deferred charges	(9,149)	(15,318)	(14,536)	6
7	Change in deferred credits	26,991	37,428	1,259	7
8	Change in deferred taxes	35,286	43,250	67,140	8
9	Change in accrued taxes	(6,709)	(18,733)	10,382	9
10	Undistributed earnings of subsidiaries	(140)	(140)	(117)	10
11	Allowance for funds used during construction	(3,899)	(3,627)	(2,296)	11
12	Change in deferred purchased gas costs	71,700	82,574	(95,608)	12
13	Change in receivable and payables	(12,422)	5,331	(8,097)	13
14	Other	(54,101)	(84,328)	(15,394)	14
15	Net cash provided by operating activities	$ 387,457	$ 382,513	$ 306,640	15
	CASH FLOWS FROM INVESTING ACTIVITIES:				
16	Construction expenditures	$ (683,078)	$ (682,847)	$ (560,433)	16
17	Investment in SWGT/UFCO	0	0	2,500	17
18	Change in customer advances	15,400	13,463	323	18
19	Miscellaneous inflows	(71)	0	2,760	19
20	Net cash used in investing activities	$ (667,749)	$ (669,384)	$ (554,850)	20
	CASH FLOWS FROM FINANCING ACTIVITIES:				
21	Change in notes payable	$ (54,000)	$ (39,000)	$ 191,000	21
22	Dividends paid	(87,000)	(87,000)	(81,497)	22
23	Withholding remittance - share-based compensation	(2,157)	(3,110)	(3,176)	23
24	Issuance of long-term debt, net	297,495	297,495	0	24
25	Retirement of long-term debt	0	0	(25,000)	25
26	Change in credit facility	0	0	145,000	26
27	Capital contribution from parent	113,549	113,549	41,359	27
28	Other	(1,021)	(1,028)	(596)	28
29	Net cash provided by (used in) financing activities	$ 266,866	$ 280,906	$ 267,090	29
30	Change in cash and cash equivalents	$ (13,426)	$ (5,965)	$ 18,880	30
31	Cash at beginning of period	49,086	37,899	19,019	31
32	Cash at end of period	$ 35,660	$ 31,934	$ 37,899	32
		Sch A-5, Sh 1	Sch A-5, Sh 1	Sch A-5, Sh 1	

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY AND PREFERRED SECURITIES

Line No.	Description	Preferred Securities Shares/Units	Preferred Securities Amount	Common # Shares	Common Amount	Additional Paid-In Capital	Retained Earnings	Capital Stock Expense/AOCI	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Balance December 31, 2016 [1]	0	$ 0	47,482,068	$ 49,111,944	$ 908,679,403	$ 767,061,448	$ (21,252,928)	1
2	Net Earnings	0	0				156,818,382		2
3	Equity Adjustment	0	0				(182,773,329)		3
4	Cash Dividend Declared - Common	0	0				(81,913,256)		4
5	Common Stock Issue	0	0	0	0	51,420,633	0	(37,153,409)	5
6	Balance December 31, 2017	0	$ 0	47,482,068	$ 49,111,944	$ 960,100,036	$ 659,193,245	$ (58,406,337)	6
7	Net Earnings	0	0				138,842,014		7
8	Equity Adjustment	0	0				9,299,742		8
9	Cash Dividend Declared - Common	0	0				(90,180,164)		9
10	Common Stock Issue	0	0	0	0	116,474,654	0	(1,975,921)	10
11	Balance December 31, 2018	0	$ 0	47,482,068	$ 49,111,944	$ 1,076,574,690	$ 717,154,837	$ (60,382,258)	11
12	Net Earnings	0	0				51,232,549		12
13	Cash Dividend Declared - Common	0	0				(1)		13
14	Common Stock Issue	0	0	0	0	(1,430,637)	0	211,819	14
15	Balance January 31, 2019	0	$ 0	47,482,068	$ 49,111,944	$ 1,075,144,053	$ 768,387,385	$ (60,170,439)	15

[1] Beginning in 2017, shares of Common Stock were distributed at the Holding Company level and not the Southwest Gas level. Common Stock shares issued at the Holding Company level for 2017 were 608,402 shares, in 2018 was 4,936,378 shares and for January 31, 2019, 50,425 shares.

SOUTHWEST GAS CORPORATION
ARIZONA
DETAIL OF UTILITY PLANT - NET ADDITIONS
FOR THE YEAR ENDED JANUARY 31, 2019

Line No.	Description	Account Number		Balance at 1/31/2019		Net Plant Additions (Deletions)		Balance at 12/31/2018	Line No.
	(a)	(b)		(c)		(d)		(e)	
				WP B-2, Sh 1, Col (c)		(c) - (e)		Company Records	
	Intangible Plant								
1	Organization	301	$	42,653	$	0	$	42,653	1
2	Franchise and Consents	302		2,208,574		0		2,208,574	2
3	Miscellaneous Intangible	303		1,968,623		0		1,968,623	3
4	Total Intangible Plant		$	4,219,850	$	0	$	4,219,850	4
	Storage Plant								
5	Land and Land Rights	360	$	1,772,673	$	0	$	1,772,673	5
6	Total Storage Plant		$	1,772,673	$	0	$	1,772,673	6
	Distribution Plant								
7	Land and Land Rights	374.1	$	405,666	$	0	$	405,666	7
8	Rights of Way	374.2		3,312,434		0		3,312,434	8
9	Structures and Improvements	375		110,557		0		110,557	9
10	Mains	376		2,101,518,186		12,915,731		2,088,602,455	10
11	Measuring and Reg. Stations	378		83,485,894		240,108		83,245,787	11
12	Services	380		1,023,123,426		1,995,687		1,021,127,738	12
13	Meters	381		307,551,428		1,945,878		305,605,550	13
14	Industrial Measuring and Reg. Sta.	385		12,445,142		151,593		12,293,548	14
15	Miscellaneous Equipment	387		432,098		0		432,098	15
16	Total Distribution Plant		$	3,532,384,830	$	17,248,997	$	3,515,135,833	16
	General Plant								
17	Land and Land Rights	389	$	17,212,657	$	0	$	17,212,657	17
18	Structures and Improv - Co. Owned	390.1		59,652,387		0		59,652,387	18
19	Structures and Improv - Leasehold	390.2		128,051		0		128,051	19
20	Office Furniture and Fixtures	391		5,361,198		(4,490)		5,365,689	20
21	Computer Software and Hardware	391.1		15,043,065		(19,612)		15,062,677	21
22	Transportation Equipment - Light	392.11		24,871,224		304,287		24,566,937	22
23	Transportation Equipment - Heavy	392.12		17,004,439		(296,696)		17,301,135	23
24	Stores Equipment	393		939,126		54,429		884,697	24
25	Tool, Shop, and Garage Equip.	394		12,154,220		(62,750)		12,216,970	25
26	Laboratory Equipment	395		557,187		(3,416)		560,603	26
27	Power-Operated Equipment	396		9,006,861		34,119		8,972,742	27
28	Communication Equipment	397		2,060,627		0		2,060,627	28
29	Telemetry Equipment	397.2		163,887		0		163,887	29
30	Miscellaneous Equipment	398		2,043,352		3,915		2,039,437	30
31	Total General Plant		$	166,198,282	$	9,785	$	166,188,497	31
32	Total Plant in Service		$	3,704,575,635	$	17,258,782	$	3,687,316,853	32
33	Construction Work in Progress			118,183,026		(9,533,207)		127,716,234	33
34	Less: Accumulated Depreciation/Amort.			1,416,558,591		17,629,420		1,398,929,172	34
35	Total Net Plant		$	2,406,200,070	$	(9,903,845)	$	2,416,103,915	35

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
DETAIL OF UTILITY PLANT - NET ADDITIONS
FOR THE YEAR ENDED JANUARY 31, 2019

Line No.	Description	Account Number	Balance at 1/31/2019	Net Plant Additions (Deletions)	Balance at 12/31/2018	Line No.
	(a)	(b)	(c)	(d)	(e)	
			WP B-2, Sh 5, Col (c)	(c) - (e)	Company Records	
	Intangible Plant					
1	Organization	301	$ 61,816	$ 0	$ 61,816	1
2	Miscellaneous Intangible	303	237,527,930	1,460,925	236,067,006	2
3	Total Intangible Plant		$ 237,589,747	$ 1,460,925	$ 236,128,822	3
	General Plant					
4	Land and Land Rights	389	$ 4,216,706	$ 0	$ 4,216,706	4
5	Structures and Improv - Co. Owned	390.1	35,012,541	(25)	35,012,566	5
6	Structures and Improv - Leasehold	390.2	2,504,821	0	2,504,821	6
7	Office Furniture and Fixtures	391	8,353,663	0	8,353,663	7
8	Computer Software and Hardware	391.1	15,976,231	549,456	15,426,775	8
9	Transportation Equipment - Light	392.11	3,361,278	(17,788)	3,379,066	9
10	Transportation Equipment - Heavy	392.12	0	0	0	10
11	Transportation Equipment - Aircraft	392.21	8,221,361	0	8,221,361	11
12	Stores Equipment	393	63,037	0	63,037	12
13	Tool, Shop, and Garage Equip.	394	1,106,311	0	1,106,311	13
14	Laboratory Equipment	395	1,112,929	0	1,112,929	14
15	Power-Operated Equipment	396	11,760	0	11,760	15
16	Communication Equipment	397	6,030,337	0	6,030,337	16
17	Telemetry Equipment	397.2	2,241	0	2,241	17
18	Miscellaneous Equipment	398	1,292,038	31,172	1,260,866	18
19	Total General Plant		$ 87,265,254	$ 562,815	$ 86,702,439	19
20	Total Plant in Service		$ 324,855,000	$ 2,023,739	$ 322,831,261	20
21	Construction Work in Progress		22,482,629	(1,596,344)	24,078,973	21
22	Less: Accumulated Depreciation/Amort.		222,449,966	195,708,418	26,741,548	22
23	Total Net Plant		$ 124,887,663	$ (195,281,022)	$ 320,168,686	23

SOUTHWEST GAS CORPORATION
ARIZONA
COMPARATIVE DEPARTMENTAL OPERATING INCOME STATEMENTS

Line No.	Description	Test Year Ended 1/31/2019	Year Ended 12/31/2018	Year Ended 12/31/2017	Line No.
	(a)	(b)	(c)	(d)	
		Company Records	Company Records	Company Records	
	Revenues				
1	Residential	$ 450,096,071	$ 434,598,290	$ 418,880,044	1
2	Small Commercial	143,936,158	144,205,349	141,971,465	2
3	Large Commercial	25,787,920	26,166,723	25,812,246	3
4	Small Industrial	9,851,333	10,038,167	9,735,420	4
5	Commercial-Compressed Nat. Gas	2,133,793	2,134,072	1,846,311	5
6	Irrigation/Water Pumping	5,831,285	5,946,124	8,029,083	6
7	Industrial-Essential Agriculture	2,225,750	2,257,662	2,254,453	7
8	Procurement Sales	1,652,473	1,640,846	794,796	8
9	Other Gas Sales	458	466	1,056	9
10	Miscellaneous Service Revenues	9,901,276	9,941,220	9,586,655	10
11	Transportation of Gas for Others	37,561,477	37,727,251	38,407,820	11
12	Rent from Gas Property	0	0	0	12
13	Accrued Unbilled Revenues	(2,039,000)	(2,445,000)	1,245,000	13
14	AZ Enabling Provision	16,344,086	32,254,274	38,832,135	14
15	LIRA Program Recovery	40,768	517,230	887,022	15
16	Tax Reform Savings	(1,462,407)	(1,827,702)	0	16
17	Total Revenues	$ 701,861,439	$ 703,154,972	$ 698,283,506	17
	Operating Expenses				
18	Other Gas Supply and Gas Cost	$ 202,440,861	$ 203,024,687	$ 187,205,169	18
19	Storage	0	0	0	19
20	Distribution	106,965,636	107,013,501	110,113,204	20
21	Customer Accounts	24,864,595	25,049,462	25,044,040	21
22	Customer Service & Info.	424,773	431,197	588,871	22
23	Sales	12,629	13,524	12,363	23
24	Administrative and General	93,507,005	92,827,980	83,510,781	24
25	Depreciation and Amortization	108,446,208	107,699,781	112,445,254	25
26	Interest on Customer Deposits	2,180,878	3,312,535	2,324,060	26
27	Taxes Other than Income	42,244,348	42,090,794	41,107,387	27
28	Income Taxes - Federal	15,237,890	15,221,082	32,817,185	28
29	Income Taxes - State	3,853,463	3,849,339	4,902,218	29
30	Total Operating Expenses	$ 600,178,284	$ 600,533,882	$ 600,070,532	30
31	Operating Income	$ 101,683,155	$ 102,621,090	$ 98,212,974	31
		Sch E-2, Sh 1,	Sch E-2, Sh 1,	Sch E-2, Sh 1,	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
OPERATING STATISTICS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Schedule Number	Average Customers [1]	Sales (Therms) [1]	Average per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Single-Family Residential Gas Service	G-5	968,714	275,092,822	284	1
2	Multi-Family Residential Gas Service	G-6	36,311	5,941,870	164	2
3	Single-Family Low Income Residential Gas Service	G-10	34,289	9,012,432	263	3
4	Multi-Family Low Income Residential Gas Service	G-11	2,824	516,375	183	4
5	Special Residential Gas Service for Air Conditioning	G-15	63	59,201	940	5
6	Master-Metered Mobile Home Park Gas Service	G-20	104	1,395,734	13,421	6
	General Gas Service	G-25				
7	Small		17,683	4,372,324	247	7
8	Medium		14,754	45,323,399	3,072	8
9	Large-1		6,903	105,796,067	15,326	9
10	Large-2		358	29,636,311	82,860	10
11	Transportation Eligible		63	20,659,072	327,922	11
12	Optional Gas Service	G-30	2	9,424,242	4,712,121	12
13	Air Conditioning Gas Service	G-40	18	228,512	12,695	13
14	Street Lighting Gas Service	G-45	5	11,108	2,222	14
15	Compression Gas Service	G-50	0	0		15
	Gas Service for Compression on Customer's Premises	G-55				
16	Residential		41	21,845	533	16
17	Small		10	20,267	2,027	17
18	Large		15	3,552,853	236,857	18
19	Electric Generation Gas Service	G-60	18	2,092,925	116,274	19
20	Biogas and Renewable Natural Gas Service	G-65	0	0		20
21	Small Essential Agriculture User Gas Service	G-75	66	2,747,497	41,734	21
22	Natural Gas Engine Gas Service	G-80	380	13,307,582	35,020	22
23	Total Gas Sales		1,082,620	529,212,438	489	23
24	Transportation Service	B-1/T-1	534	176,157,403	329,883	24
25	Total Arizona		1,083,154	705,369,841	651	25

[1] Workpapers, Schedule H-2, Sheets 5-7.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
OPERATING STATISTICS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2017

Line No.	Description	Schedule Number	Average Customers [1]	Sales (Therms) [1]	Average per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Single-Family Residential Gas Service	G-5	943,407	239,880,730	254	1
2	Multi-Family Residential Gas Service	G-6	35,627	5,555,892	156	2
3	Single-Family Low Income Residential Gas Service	G-10	34,578	8,276,019	239	3
4	Multi-Family Low Income Residential Gas Service	G-11	2,884	514,498	178	4
5	Special Residential Gas Service for Air Conditioning	G-15	69	63,652	922	5
6	Master-Metered Mobile Home Park Gas Service	G-20	112	1,298,040	11,616	6
	General Gas Service	G-25				
7	Small		16,854	3,200,411	190	7
8	Medium		15,256	42,459,805	2,783	8
9	Large-1		6,901	102,651,515	14,874	9
10	Large-2		368	29,820,277	81,015	10
11	Transportation Eligible		57	18,090,881	319,251	11
12	Optional Gas Service	G-30	2	6,748,351	3,374,176	12
13	Air Conditioning Gas Service	G-40	21	237,804	11,415	13
14	Street Lighting Gas Service	G-45	7	15,650	2,408	14
	Gas Service for Compression on Customer's Premises	G-55				
15	Residential		46	24,988	547	15
16	Small		16	49,800	3,145	16
17	Large		17	2,703,755	159,044	17
18	Electric Generation Gas Service	G-60	16	418,907	26,457	18
19	Small Essential Agriculture User Gas Service	G-75	68	2,867,693	42,328	19
20	Natural Gas Engine Gas Service	G-80	382	14,563,094	38,157	20
21	Total Gas Sales		1,056,687	479,441,762	454	21
22	Transportation Service	B-1/T-1	511	173,473,746	339,534	22
23	Total Arizona		1,057,198	652,915,508	618	23

[1] Workpapers, Schedule H-2, Sheets 59-66.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
OPERATING STATISTICS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2016

Line No.	Description	Schedule Number	Average Customers [1]	Sales (Therms) [1]	Average per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Single-Family Residential Gas Service	G-5	925,574	259,043,588	280	1
2	Multi-Family Residential Gas Service	G-6	34,940	5,792,310	166	2
3	Single-Family Low Income Residential Gas Service	G-10	37,284	9,990,435	268	3
4	Multi-Family Low Income Residential Gas Service	G-11	3,231	625,179	193	4
5	Special Residential Gas Service for Air Conditioning	G-15	75	65,092	870	5
6	Master-Metered Mobile Home Park Gas Service	G-20	115	1,453,900	12,615	6
	General Gas Service	G-25				
7	Small		16,444	4,125,356	251	7
8	Medium		15,535	43,247,101	2,784	8
9	Large-1		6,878	103,367,789	15,028	9
10	Large-2		352	28,562,473	81,067	10
11	Transportation Eligible		62	19,251,711	310,929	11
12	Optional Gas Service	G-30	2	6,422,397	3,211,199	12
13	Air Conditioning Gas Service	G-40	21	239,346	11,263	13
14	Street Lighting Gas Service	G-45	7	13,305	2,021	14
	Gas Service for Compression on Customer's Premises	G-55				
15	Residential		52	28,007	536	15
16	Small		15	43,140	2,829	16
17	Large		16	2,053,436	125,721	17
18	Electric Generation Gas Service	G-60	16	248,790	15,713	18
19	Small Essential Agriculture User Gas Service	G-75	74	3,099,070	41,927	19
20	Natural Gas Engine Gas Service	G-80	378.33	11,899,146.00	31,451	20
21	Total Gas Sales		1,041,072	499,571,571	480	21
22	Transportation Service	B-1/T-1	496	169,530,230	341,565	22
23	Total Arizona		1,041,568	669,101,801	642	23

[1] Workpapers, Schedule H-2, Sheets 67-78.

SOUTHWEST GAS CORPORATION
ARIZONA
TAXES CHARGED TO OPERATIONS
AS RECORDED AT JANUARY 31, 2019

Line No.	Description	Year Ended 12/31/2017	Year Ended 12/31/2018	Test Year Ended 1/31/2019	Line No.
	(a)	(b)	(c)	(d)	
		Sch E-6, Sh 1, Col (d), Lns 27-29	Sch E-6, Sh 1, Col (c), Lns 27-29	Sch E-6, Sh 1, Col (b), Lns 27-29	
	Federal Taxes				
1	Federal Income Tax	$ 32,817,185	$ 15,221,082	$ 15,237,874	1
	State Taxes				
2	State Income Tax	$ 4,902,218	$ 3,849,339	$ 3,853,459	2
	Local Taxes				
3	Property and Miscellaneous	$ 41,107,387	$ 42,090,794	$ 42,244,348	3

SOUTHWEST GAS CORPORATION
ARIZONA
NOTES TO FINANCIAL STATEMENTS

1. The Company uses the accrual method of accounting as prescribed by the Uniform System of Accounts.

2. The Company uses the straight-line method for calculating depreciation expense. Depreciation rates by major classification can be found in the Workpapers, Schedule C-2.

3. The Allowance for Funds Used During Construction (AFUDC) rate used in 2018 was 5.85%.

4. The Notes to the Financial Statements included in the 2018 Annual Report can be found at the following location on the Company's website:

http://investors.southwestgas.com/phoenix.zhtml?c=117697&p=irol-reportsannual

SCHEDULE F

SOUTHWEST GAS CORPORATION
ARIZONA
PROJECTED INCOME STATEMENTS - PRESENT AND PROPOSED RATES

Line No.	Description	Test Year Ended 1/31/2019	Projected Year Present Rates 1/31/2020	Projected Year Proposed Rates 1/31/2020	Line No.
	(a)	(b)	(c)	(d)	
		Sch A-1, Sh 2, Col (c)		Sch A-1, Sh 2, Col (g)	
1	Operating Margin	$ 500,687,809	$ 505,694,687	$ 575,219,806	1
	Operating Expenses				
2	Other Gas Supply Expenses	$ 1,267,230	$ 1,360,309	$ 1,358,147	2
3	Storage	0	1,492,139	1,470,088	3
4	Distribution Expenses	106,965,636	109,606,983	108,962,028	4
5	Customer Accounts Expenses	24,864,595	25,871,749	25,758,507	5
6	Customer Service & Info. Expenses	424,773	385,057	379,366	6
7	Sales Expenses	12,629	7,465	7,579	7
8	Administrative and General Expenses	93,507,005	94,421,360	93,808,967	8
9	Depreciation and Amortization Expenses	108,446,208	119,258,528	112,627,474	9
10	Taxes Other than Income	42,244,348	42,878,013	58,155,759	10
11	Interest on Customer Deposits	2,180,878	2,180,878	958,434	11
12	Federal Income Taxes	15,237,890	13,200,790	9,386,492	12
13	State Income Taxes	3,853,463	3,238,890	6,095,778	13
14	Total Operating Expenses	$ 399,004,654	$ 413,902,161	$ 418,968,620	14
15	Operating Income	$ 101,683,155	$ 91,792,526	$ 156,251,187	15
16	Less: Interest Expense	42,132,413	42,132,413	47,329,818	16
17	Net Income	$ 59,550,742	$ 49,660,113	$ 108,921,369	17
			Sch A-2, Sh 1, Ln 5(f)	Sch A-2, Sh 1, Ln 5(g)	
18	Earnings per Share of Average Common Stock Outstanding [1]	N/A	N/A	N/A	18
19	Percent Return on Common Equity [1]	N/A	N/A	N/A	19

[1] Projections of earnings per share and return on common equity were not performed because these statistics do not pertain solely to Arizona.

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
COMPARATIVE STATEMENT OF CASH FLOWS
PROJECTED CHANGES IN FINANCIAL POSITION
($ THOUSANDS)

Line No.	Description	Test Year Ended 1/31/2019	Projected Year: At Present Rates Year Ending [1] 1/31/2020	Projected Year: At Proposed Rates Year Ending [1] 1/31/2020	Line No.
	(a)	(b)	(c)	(d)	
		Sch E-3, Sh 1 Col (b)			
	CASH FLOWS FROM OPERATING ACTIVITIES:				
1	Net Income	$ 140,721	$ 140,721	$ 183,463	1
2	Adjustments to reconcile net income to net cash				2
3	provided by operating activities:				3
4	Depreciation and amortization	193,743	203,491	203,491	4
5	Other Amortization	5,436	5,436	5,436	5
6	Change in deferred charges	(9,149)	(9,149)	(9,149)	6
7	Change in deferred credits	26,991	26,991	26,991	7
8	Change in deferred taxes	35,286	35,286	35,286	8
9	Change in accrued taxes	(6,709)	(6,709)	(6,709)	9
10	Undistributed earnings of subsidiaries	(140)	(140)	(140)	10
11	Allowance for funds used during construction	(3,899)	(3,899)	(3,899)	11
12	Change in deferred purchased gas costs	71,700	71,700	71,700	12
13	Change in receivable and payables	(12,422)	(12,422)	(12,422)	13
14	Other	(54,101)	(54,101)	(54,101)	14
15	Net cash provided by operating activities	$ 387,457	$ 397,205	$ 439,947	15
			Sch A-5, Sh 1, Ln 1(e)	Sch A-5, Sh 1, Ln 1(f)	
	CASH FLOWS FROM INVESTING ACTIVITIES:				
16	Construction expenditures	$ (683,078)	$ (324,930)	$ (324,930)	16
17	Investment in SWGT/UFCO	0	0	0	17
18	Change in customer advances	15,400	15,400	15,400	18
19	Miscellaneous inflows	(71)	(71)	(71)	19
20	Net cash used in investing activities	$ (667,749)	$ (309,601)	$ (309,601)	20
			Sch A-5, Sh 1, Ln 2(e)	Sch A-5, Sh 1, Ln 2(f)	
	CASH FLOWS FROM FINANCING ACTIVITIES:				
21	Change in notes payable	$ (54,000)	$ (2,000)	$ (2,000)	21
22	Dividends paid	(87,000)	(91,900)	(91,900)	22
23	Withholding remittance - share-based compensation	(2,157)	0	0	23
24	Issuance of long-term debt, net	297,495	300,000	300,000	24
25	Retirement of long-term debt	0	0	0	25
26	Change in credit facility	0	0	0	26
27	Capital contribution from parent	113,549	186,120	186,120	27
28	Other	(1,021)	(2,203)	(2,203)	28
29	Net cash provided by (used in) financing activities	$ 266,866	$ 390,017	$ 390,017	29
			Sch A-5, Sh 1, Ln 3(e)	Sch A-5, Sh 1, Ln 3(f)	
30	Change in cash and cash equivalents	$ (13,426)	$ 477,621	$ 520,363	30
31	Cash at beginning of period	49,086	35,660	35,660	31
32	Cash at end of period	$ 35,660	$ 513,281	$ 556,023	32

[1] Prepared based on year ended December 31 consistent with historical cash flows provided on Schedule E-3.

SOUTHWEST GAS CORPORATION
ARIZONA
CONSTRUCTION EXPENDITURES BY PROPERTY CLASSIFICATION
TEST YEAR AND PROJECTED YEARS

Line No.	Description	Test Year Ended 1/31/2019	Projected [2] Year Ending 1/31/2020	Year Ending 1/30/2021	Year Ending 1/30/2022	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Intangible Plant					
1	Arizona Direct	$ 0	$ 50,000	$ 350,000	$ 350,000	1
2	System Allocable [1]	5,600,892	35,904,319	22,616,280	22,616,280	2
3	Total Intangible Plant	$ 5,600,892	$ 35,954,319	$ 22,966,280	$ 22,966,280	3
	Distribution Plant					
4	Arizona Direct	$ 329,295,111	$ 289,480,729	$ 283,643,077	$ 283,643,077	4
5	System Allocable [1]	0	125,275	125,275	125,275	5
6	Total Distribution Plant	$ 329,295,111	$ 289,606,004	$ 283,768,352	$ 283,768,352	6
	General Plant					
7	Arizona Direct	$ 18,807,824	$ 12,518,582	$ 18,014,702	$ 18,014,702	7
8	System Allocable [1]	1,791,527	10,334,497	11,404,892	11,404,892	8
9	Total General Plant	$ 20,599,351	$ 22,853,079	$ 29,419,594	$ 29,419,594	9
10	Total Arizona Plant Construction	$ 355,495,353	$ 348,413,401	$ 336,154,226	$ 336,154,226	10

[1] After 4-Factor allocation to AZ. Schedule C-1,Sheet 17, Ln 9(c)
[2] Projections are based on budgets which are compiled on an annual basis.

SOUTHWEST GAS CORPORATION
ARIZONA
ASSUMPTIONS USED IN DEVELOPING PROJECTIONS

1. Customer Growth
   Margin related to customer growth is anticipated to increase by 1% in the year following the test year.

2. Growth in Consumption and Customer Demand
   Margin related to growth in consumption is anticipated to increase by 1% in the year following the test year.

3. Changes in Expenses
   Operation and Maintenance Expenses – The actual amounts for the recorded test year were adjusted to give the annual effect for known and measurable changes occurring during the test year. The operation and maintenance expenses for the projected year were calculated by taking the adjusted test year and generally increasing the non-labor expenses by 1.5%.

   Depreciation and Amortization Expenses – The actual amounts for the recorded test year were adjusted to annualize depreciation expense at the end of the test period plant balances, and to reflect depreciation expense on projected construction expenditures.

4. Construction Requirements, Including Production
   Reserves and Changes in Plant Capacity Additions to gas plant were based upon anticipated construction expenditures.

SCHEDULE G

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
CLASS COST OF SERVICE STUDY SUMMARY - PRESENT RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor	Total Amount	Single-Family Residential	Multi-Family Residential	Master-Metered Mobile Home Park (MMMHP)	Small General	Medium General	Large-1 General	Large-2 General
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Rate Base									
1	Total Direct Net Plant		$ 3,155,975,561	$ 2,382,867,602	$ 85,768,433	$ 3,244,561	$ 47,482,723	$ 193,001,167	$ 197,420,544	$ 66,868,825
2	Total Common Systems Allocable Net Plant		$ 95,625,305	72,758,129	2,640,527	95,163	1,452,392	5,836,444	5,782,498	1,961,994
3	Cash Working Capital	1.1	(10,297,032)	(7,576,663)	(284,962)	(7,259)	(145,520)	(915,380)	(670,537)	(254,757)
4	Materials & Supplies	1.1	36,813,908	28,010,484	1,016,552	36,636	559,143	2,246,919	2,226,151	755,330
5	Prepayments	1.1	7,721,011	5,874,662	213,202	7,684	117,270	471,248	466,892	158,416
6	Other	1.1	0	0	0	0	0	0	0	0
7	Customer Deposits	8.0	(36,862,844)	(32,667,363)	(3,007,397)	(4,457)	(521,720)	(470,236)	(167,303)	(10,995)
8	Customer Advances	8.0	(41,613,406)	(36,877,248)	(3,394,964)	(5,032)	(588,954)	(530,836)	(188,864)	(12,412)
9	Deferred Taxes	1.1	(594,534,243)	(452,361,423)	(16,417,032)	(591,662)	(9,030,003)	(36,287,109)	(35,951,708)	(12,198,369)
10	Other	1.1	0	0	0	0	0	0	0	0
11	Total Rate Base		$ 2,612,828,261	$ 1,960,028,180	$ 66,534,359	$ 2,775,634	$ 39,325,331	$ 163,352,217	$ 168,917,674	$ 57,268,033
	Margin									
12	Net Operating Margin	Direct	$ 483,951,321	$ 335,014,130	$ 9,419,074	$ 754,847	$ 9,318,018	$ 26,495,367	$ 48,738,803	$ 13,002,722
13	Special Contract & Optional Margin	Net Op Margin	5,008,186	3,466,905	97,474	7,812	96,428	274,188	504,375	134,559
14	Other Revenue	Various	9,673,541	8,417,490	731,315	1,481	128,056	172,278	135,088	33,035
15	Total Revenue		$ 498,633,048	$ 346,898,525	$ 10,247,863	$ 764,140	$ 9,542,502	$ 26,941,833	$ 49,378,266	$ 13,170,316
	Operating Expenses									
16	Operations & Maintenance Expense		$ (137,825,696)	$ (101,413,575)	$ (3,814,219)	$ (97,156)	$ (1,947,787)	$ (12,252,352)	$ (8,975,128)	$ (3,409,915)
17	Administrative & General Expense	Total O&M	(93,808,967)	(69,025,609)	(2,596,090)	(66,128)	(1,325,732)	(8,339,377)	(6,108,784)	(2,320,907)
18	Depreciation Expense	Deprec Exp	(112,627,474)	(84,839,935)	(3,046,029)	(116,903)	(1,689,674)	(6,891,697)	(7,115,955)	(2,409,063)
19	Interest on Customer Deposits	8.0	(958,434)	(894,432)	(34,897)	(93)	(15,774)	(13,239)	0	0
20	Taxes Other Than Income	1.1	(58,155,759)	(44,248,792)	(1,605,870)	(57,875)	(883,291)	(3,549,509)	(3,516,701)	(1,193,212)
21	Total Operating Deductions		$ (403,376,330)	$ (300,422,344)	$ (11,097,104)	$ (338,154)	$ (5,862,257)	$ (31,046,174)	$ (25,716,567)	$ (9,333,097)
	Taxable Income									
22	Taxable Income before Interest Expense		$ 95,256,717	$ 46,476,181	$ (849,241)	$ 425,986	$ 3,680,244	$ (4,104,342)	$ 23,661,698	$ 3,837,219
23	Interest Expense	1.1	(47,329,818)	(36,011,691)	(1,306,931)	(47,101)	(718,863)	(2,888,752)	(2,862,052)	(971,091)
24	Total Taxable Income		$ 47,926,899	$ 10,464,489	$ (2,156,172)	$ 378,885	$ 2,961,382	$ (6,993,094)	$ 20,799,647	$ 2,866,128
	State Income Tax									
25	State Income Tax	4.90%	$ 2,348,418	$ 512,760	$ (105,652)	$ 18,565	$ 145,108	$ (342,662)	$ 1,019,183	$ 140,440
26	Total State Income Tax		$ 2,348,418	$ 512,760	$ (105,652)	$ 18,565	$ 145,108	$ (342,662)	$ 1,019,183	$ 140,440
	Federal Income Tax									
27	Federal Income Tax	19.97%	$ 9,571,481	$ 2,089,863	$ (430,609)	$ 75,667	$ 591,418	$ (1,396,591)	$ 4,153,897	$ 572,394
28	ARAM Federal	1.1	(15,458,159)	(11,761,601)	(426,850)	(15,383)	(234,784)	(943,481)	(934,761)	(317,163)
29	Total Federal Income Tax		$ (5,886,678)	$ (9,671,738)	$ (857,459)	$ 60,284	$ 356,633	$ (2,340,072)	$ 3,219,137	$ 255,231
30	Regulatory Amortization	Deprec Exp	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
31	Net Income		$ 98,794,977	$ 55,635,159	$ 113,871	$ 347,137	$ 3,178,503	$ (1,421,608)	$ 19,423,379	$ 3,441,547
32	Rate of Return on Rate Base		3.78%	2.84%	0.17%	12.51%	8.08%	-0.87%	11.50%	6.01%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
CLASS COST OF SERVICE STUDY SUMMARY - PRESENT RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor	Total Amount	Transportation Eligible General	Air Conditioning	Street Lighting	Compression on Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	Rate Base										
1	Total Direct Net Plant		$ 3,155,975,561	$ 143,806,650	$ 191,916	$ 92,628	$ 12,031,036	$ 12,688,864	$ 4,830,155	$ 5,680,457	1
2	Total Common Systems Allocable Net Plant		$ 95,625,305	4,107,335	5,285	2,846	344,263	358,250	136,600	143,580	2
3	Cash Working Capital	1.1	(10,297,032)	(343,798)	(569)	(275)	(35,040)	(28,823)	(11,824)	(21,626)	3
4	Materials & Supplies	1.1	36,813,908	1,581,245	2,035	1,095	132,535	137,919	52,589	55,275	4
5	Prepayments	1.1	7,721,011	331,636	427	230	27,797	28,926	11,029	11,593	5
6	Other	1.1	0	0	0	0	0	0	0	0	6
7	Customer Deposits	8.0	(36,862,844)	0	0	(594)	(1,189)	(297)	(5,943)	(5,349)	7
8	Customer Advances	8.0	(41,613,406)	0	0	(671)	(1,342)	(335)	(6,709)	(6,038)	8
9	Deferred Taxes	1.1	(594,534,243)	(25,536,662)	(32,860)	(17,691)	(2,140,397)	(2,227,356)	(849,290)	(892,682)	9
10	Other	1.1	0	0	0	0	0	0	0	0	10
11	Total Rate Base		$ 2,612,828,261	$ 123,946,406	$ 166,234	$ 77,567	$ 10,357,663	$ 10,957,147	$ 4,156,607	$ 4,965,210	11
	Margin										
12	Net Operating Margin	Direct	$ 483,951,321	$ 31,846,016	$ 41,713	$ 8,165	$ 2,310,233	$ 2,395,014	$ 1,337,328	$ 3,269,891	12
13	Special Contract & Optional Margin	Net Op Margin	5,008,186	329,560	432	84	23,908	24,785	13,839	33,839	13
14	Other Revenue	Various	9,673,541	33,991	570	386	2,726	1,517	3,540	12,068	14
15	Total Revenue		$ 498,633,048	$ 32,209,567	$ 42,714	$ 8,636	$ 2,336,866	$ 2,421,316	$ 1,354,707	$ 3,315,797	15
	Operating Expenses										
16	Operations & Maintenance Expense		$ (137,825,696)	$ (4,601,731)	$ (7,612)	$ (3,687)	$ (469,014)	$ (385,795)	$ (158,266)	$ (289,459)	16
17	Administrative & General Expense	Total O&M	(93,808,967)	(3,132,098)	(5,181)	(2,510)	(319,227)	(262,586)	(107,721)	(197,016)	17
18	Depreciation Expense	Deprec Exp	(112,627,474)	(5,220,583)	(7,037)	(3,292)	(436,534)	(462,116)	(175,829)	(212,827)	18
19	Interest on Customer Deposits	8.0	(958,434)	0	0	0	0	0	0	0	19
20	Taxes Other Than Income	1.1	(58,155,759)	(2,497,928)	(3,214)	(1,731)	(209,368)	(217,874)	(83,075)	(87,320)	20
21	Total Operating Deductions		$ (403,376,330)	$ (15,452,341)	$ (23,045)	$ (11,220)	$ (1,434,143)	$ (1,328,371)	$ (524,891)	$ (786,622)	21
	Taxable Income										
22	Taxable Income before Interest Expense		$ 95,256,717	$ 16,757,226	$ 19,670	$ (2,584)	$ 902,723	$ 1,092,945	$ 829,816	$ 2,529,175	22
23	Interest Expense	1.1	(47,329,818)	(2,032,928)	(2,616)	(1,408)	(170,393)	(177,316)	(67,610)	(71,065)	23
24	Total Taxable Income		$ 47,926,899	$ 14,724,297	$ 17,054	$ (3,992)	$ 732,330	$ 915,629	$ 762,206	$ 2,458,111	24
	State Income Tax										
25	State Income Tax	4.90%	$ 2,348,418	$ 721,491	$ 836	$ (196)	$ 35,884	$ 44,866	$ 37,348	$ 120,447	25
26	Total State Income Tax		$ 2,348,418	$ 721,491	$ 836	$ (196)	$ 35,884	$ 44,866	$ 37,348	$ 120,447	26
	Federal Income Tax										
27	Federal Income Tax	19.97%	$ 9,571,481	$ 2,940,589	$ 3,406	$ (797)	$ 146,254	$ 182,860	$ 152,220	$ 490,909	27
28	ARAM Federal	1.1	(15,458,159)	(663,965)	(854)	(460)	(55,651)	(57,912)	(22,082)	(23,210)	28
29	Total Federal Income Tax		$ (5,886,678)	$ 2,276,625	$ 2,551	$ (1,257)	$ 90,602	$ 124,948	$ 130,138	$ 467,699	29
30	Regulatory Amortization	Deprec Exp	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	30
31	Net Income		$ 98,794,977	$ 13,759,110	$ 16,283	$ (1,131)	$ 776,237	$ 923,131	$ 662,330	$ 1,941,029	31
32	Rate of Return on Rate Base		3.78%	11.10%	9.80%	-1.46%	7.49%	8.42%	15.93%	39.09%	32

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
CLASS COST OF SERVICE STUDY SUMMARY - PRESENT RATE SCHEDULES AT SYSTEM RATE OF RETURN
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor	Total Amount	Single-Family Residential	Multi-Family Residential	Master-Metered Mobile Home Park (MMMHP)	Small General	Medium General	Large-1 General	Large-2 General	Transportation Eligible General	Air Conditioning	Street Lighting	Compression on Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	
	Rate Base																	
1	Total Direct Net Plant		$ 3,155,975,561	$ 2,382,867,602	$ 85,768,433	$ 3,244,561	$ 47,482,723	$ 193,001,167	$ 197,420,544	$ 66,868,825	$ 143,806,650	$ 191,916	$ 92,628	$ 12,031,036	$ 12,688,864	$ 4,830,155	$ 5,680,457	1
2	Total Common Systems Allocable Net Plant		95,625,305	72,758,129	2,640,527	95,163	1,452,392	5,836,444	5,782,498	1,961,994	4,107,335	5,285	2,846	344,263	358,250	136,600	143,580	2
3	Cash Working Capital	1.1	(10,297,032)	(7,576,663)	(284,962)	(7,259)	(145,520)	(915,380)	(670,537)	(254,757)	(343,798)	(569)	(275)	(35,040)	(28,823)	(11,824)	(21,626)	3
4	Materials & Supplies	1.1	36,813,908	28,010,484	1,016,552	36,636	559,143	2,246,919	2,226,151	755,330	1,581,245	2,035	1,095	132,535	137,919	52,589	55,275	4
5	Prepayments	1.1	7,721,011	5,874,662	213,202	7,684	117,270	471,248	466,892	158,416	331,636	427	230	27,797	28,926	11,029	11,593	5
6	Other	1.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
7	Customer Deposits	8.0	(36,862,844)	(32,667,363)	(3,007,397)	(4,457)	(521,720)	(470,236)	(167,303)	(10,995)	0	0	(594)	(1,189)	(297)	(5,943)	(5,349)	7
8	Customer Advances	8.0	(41,613,406)	(36,877,248)	(3,394,964)	(5,032)	(588,954)	(530,836)	(188,864)	(12,412)	0	0	(671)	(1,342)	(335)	(6,709)	(6,038)	8
9	Deferred Taxes	1.1	(594,534,243)	(452,361,423)	(16,417,032)	(591,662)	(9,030,003)	(36,287,109)	(35,951,708)	(12,198,369)	(25,536,662)	(32,860)	(17,691)	(2,140,397)	(2,227,356)	(849,290)	(892,682)	9
10	Other	1.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10
11	Total Rate Base		$ 2,612,828,261	$ 1,960,028,180	$ 66,534,359	$ 2,775,634	$ 39,325,331	$ 163,352,217	$ 168,917,674	$ 57,268,033	$ 123,946,406	$ 166,234	$ 77,567	$ 10,357,663	$ 10,957,147	$ 4,156,607	$ 4,965,210	11
	Margin																	
12	Net Operating Margin	Direct	$ 560,538,080	$ 416,815,200	$ 14,534,365	$ 517,007	$ 8,242,647	$ 41,294,681	$ 36,514,096	$ 12,999,217	$ 23,520,245	$ 33,410	$ 15,792	$ 2,106,696	$ 2,045,128	$ 793,514	$ 1,106,081	12
13	Other Revenue		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	13
14	Special Contract & Optional Margin	Net Op Margin	5,008,186	3,724,079	129,859	4,619	73,645	368,952	326,239	116,143	210,144	299	141	18,822	18,272	7,090	9,882	14
15	Late Charges	12	1,615,145	1,290,032	85,387	383	17,255	65,382	87,311	27,490	26,176	559	264	1,920	856	2,012	10,117	15
16	Service Establishment Charges	9	7,218,698	6,397,114	588,926	873	102,166	92,084	32,762	2,153	0	0	116	233	58	1,164	1,047	16
17	Reconnect / Reread Charges	9	224,248	198,726	18,295	27	3,174	2,861	1,018	67	0	0	4	7	2	36	33	17
18	Other Revenue - Labor	Net Op Margin	4,325	3,216	112	4	64	319	282	100	181	0	0	16	16	6	9	18
19	Other Revenue - Parts & Material	Net Op Margin	377	280	10	0	6	28	25	9	16	0	0	1	1	1	1	19
20	Other Revenue - Field Collection Fee	Net Op Margin	(21)	(15)	(0)	(0)	(0)	(1)	(2)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	20
21	Other Revenue - Returned Item Fee	13	496,902	449,554	36,400	14	3,178	5,460	2,058	140	14	0	0	0	14	0	70	21
22	Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	84,671	2,952	105	1,674	8,389	7,417	2,641	4,778	7	3	428	415	161	225	22
23	Other Revenue	Various	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23
24	Total Revenue		$ 575,219,806	$ 428,962,857	$ 15,396,306	$ 523,032	$ 8,443,808	$ 41,838,154	$ 36,971,205	$ 13,147,959	$ 23,761,554	$ 34,275	$ 16,321	$ 2,128,123	$ 2,064,763	$ 803,984	$ 1,127,464	24
	Operating Deductions																	
25	Operations & Maintenance Expense		$ (137,825,696)	$ (101,413,575)	$ (3,814,219)	$ (97,156)	$ (1,947,787)	$ (12,252,352)	$ (8,975,128)	$ (3,409,915)	$ (4,601,731)	$ (7,612)	$ (3,687)	$ (469,014)	$ (385,795)	$ (158,266)	$ (289,459)	25
26	Incremental Uncollectible Expense		(110,019)	(101,881)	(3,975)	(11)	(1,797)	(1,508)	(718)	(44)	(21)	(2)	(6)	(8)	(3)	(7)	(39)	26
27	Administrative & General Expense	Total O&M	(93,808,967)	(69,025,609)	(2,596,090)	(66,128)	(1,325,732)	(8,339,377)	(6,108,784)	(2,320,907)	(3,132,098)	(5,181)	(2,510)	(319,227)	(262,586)	(107,721)	(197,016)	27
28	Depreciation Expense	Deprec Exp	(112,627,474)	(84,839,935)	(3,046,029)	(116,903)	(1,689,674)	(6,891,697)	(7,115,955)	(2,409,063)	(5,220,583)	(7,037)	(3,292)	(436,534)	(462,116)	(175,829)	(212,827)	28
29	Interest on Customer Deposits	8	(958,434)	(894,432)	(34,897)	(93)	(15,774)	(13,239)	0	0	0	0	0	0	0	0	0	29
30	Taxes Other Than Income	1	(58,155,759)	(44,248,792)	(1,605,870)	(57,875)	(883,291)	(3,549,509)	(3,516,701)	(1,193,212)	(2,497,928)	(3,214)	(1,731)	(209,368)	(217,874)	(83,075)	(87,320)	30
31	Total Operating Deductions		$ (403,486,349)	$ (300,524,225)	$ (11,101,079)	$ (338,165)	$ (5,864,054)	$ (31,047,682)	$ (25,717,286)	$ (9,333,141)	$ (15,452,362)	$ (23,046)	$ (11,226)	$ (1,434,151)	$ (1,328,374)	$ (524,898)	$ (786,661)	31
	State Income Tax																	
32	Taxable Income before Interest Expense		$ 171,733,457	$ 128,438,632	$ 4,295,227	$ 184,868	$ 2,579,754	$ 10,790,472	$ 11,253,919	$ 3,814,817	$ 8,309,192	$ 11,229	$ 5,096	$ 693,972	$ 736,389	$ 279,086	$ 340,804	32
33	Interest Expense	1	(47,329,818)	(36,011,691)	(1,306,931)	(47,101)	(718,863)	(2,888,752)	(2,862,052)	(971,091)	(2,032,928)	(2,616)	(1,408)	(170,393)	(177,316)	(67,610)	(71,065)	33
34	Total State Taxable Income		$ 124,403,639	$ 92,426,941	$ 2,988,296	$ 137,767	$ 1,860,891	$ 7,901,719	$ 8,391,868	$ 2,843,727	$ 6,276,264	$ 8,613	$ 3,687	$ 523,579	$ 559,073	$ 211,475	$ 269,739	34
35	State Income Tax	4.90%	$ 6,095,778	$ 4,528,920	$ 146,427	$ 6,751	$ 91,184	$ 387,184	$ 411,202	$ 139,343	$ 307,537	$ 422	$ 181	$ 25,655	$ 27,395	$ 10,362	$ 13,217	35
36	Total State Income Tax		$ 6,095,778	$ 4,528,920	$ 146,427	$ 6,751	$ 91,184	$ 387,184	$ 411,202	$ 139,343	$ 307,537	$ 422	$ 181	$ 25,655	$ 27,395	$ 10,362	$ 13,217	36
	Federal Income Tax																	
37	Taxable Income before Interest Expense		$ 171,733,457	$ 128,438,632	$ 4,295,227	$ 184,868	$ 2,579,754	$ 10,790,472	$ 11,253,919	$ 3,814,817	$ 8,309,192	$ 11,229	$ 5,096	$ 693,972	$ 736,389	$ 279,086	$ 340,804	37
38	Interest Expense	1	(47,329,818)	(36,011,691)	(1,306,931)	(47,101)	(718,863)	(2,888,752)	(2,862,052)	(971,091)	(2,032,928)	(2,616)	(1,408)	(170,393)	(177,316)	(67,610)	(71,065)	38
39	Total Federal Taxable Income		$ 124,403,639	$ 92,426,941	$ 2,988,296	$ 137,767	$ 1,860,891	$ 7,901,719	$ 8,391,868	$ 2,843,727	$ 6,276,264	$ 8,613	$ 3,687	$ 523,579	$ 559,073	$ 211,475	$ 269,739	39
40	Federal Income Tax	19.97%	$ 24,844,651	$ 18,458,584	$ 596,793	$ 27,513	$ 371,639	$ 1,578,052	$ 1,675,940	$ 567,921	$ 1,253,433	$ 1,720	$ 736	$ 104,564	$ 111,653	$ 42,234	$ 53,870	40
41	ARAM Federal	1	(15,458,159)	(11,761,601)	(426,850)	(15,383)	(234,784)	(943,481)	(934,761)	(317,163)	(663,965)	(854)	(460)	(55,651)	(57,912)	(22,082)	(23,210)	41
42	Total Federal Income Tax		$ 9,386,492	$ 6,696,983	$ 169,942	$ 12,130	$ 136,854	$ 634,571	$ 741,179	$ 250,758	$ 589,468	$ 866	$ 276	$ 48,913	$ 53,740	$ 20,152	$ 30,659	42
43	Regulatory Amortization	1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	43
44	Net Income		$ 156,251,187	$ 117,212,729	$ 3,978,858	$ 165,987	$ 2,351,716	$ 9,768,716	$ 10,101,539	$ 3,424,717	$ 7,412,187	$ 9,941	$ 4,639	$ 619,404	$ 655,254	$ 248,572	$ 296,927	44
45	Rate of Return on Rate Base		5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	5.98%	45

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
CLASS COST OF SERVICE STUDY SUMMARY - PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor	Total Amount	Single-Family Residential	Multi-Family Residential	Master-Metered Mobile Home Park (MMMHP)	Small General	Medium General	Large-1 General	Large-2 General
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Rate Base									
1	Total Direct Net Plant		$ 3,155,975,561	$ 2,382,867,602	$ 85,768,433	$ 3,244,561	$ 47,482,723	$ 193,001,167	$ 197,420,544	$ 66,868,825
2	Total Common Systems Allocable Net Plant		95,625,305	72,758,129	2,640,527	95,163	1,452,392	5,836,444	5,782,498	1,961,994
3	Cash Working Capital	1.1	(10,297,032)	(7,576,663)	(284,962)	(7,259)	(145,520)	(915,380)	(670,537)	(254,757)
4	Materials & Supplies	1.1	36,813,908	28,010,484	1,016,552	36,636	559,143	2,246,919	2,226,151	755,330
5	Prepayments	1.1	7,721,011	5,874,662	213,202	7,684	117,270	471,248	466,892	158,416
6	Other	1.1	0	0	0	0	0	0	0	0
7	Customer Deposits	8.0	(36,862,844)	(32,667,363)	(3,007,397)	(4,457)	(521,720)	(470,236)	(167,303)	(10,995)
8	Customer Advances	8.0	(41,613,406)	(36,877,248)	(3,394,964)	(5,032)	(588,954)	(530,836)	(188,864)	(12,412)
9	Deferred Taxes	1.1	(594,534,243)	(452,361,423)	(16,417,032)	(591,662)	(9,030,003)	(36,287,109)	(35,951,708)	(12,198,369)
10	Other	1.1	0	0	0	0	0	0	0	0
11	Total Rate Base		$ 2,612,828,261	$ 1,960,028,180	$ 66,534,359	$ 2,775,634	$ 39,325,331	$ 163,352,217	$ 168,917,674	$ 57,268,033
	Margin									
12	Net Operating Margin	Direct	$ 560,538,080	$ 394,459,989	$ 11,380,744	$ 807,422	$ 10,286,811	$ 30,124,775	$ 54,651,719	$ 14,606,096
13	Special Contract & Optional Margin	Net Op Margin	5,126,755	3,812,247	132,933	4,729	75,388	377,687	333,963	118,893
14	Other Revenue	Various	9,554,972	8,335,411	729,008	1,297	125,773	165,786	123,147	29,849
15	Total Revenue		$ 575,219,806	$ 406,607,647	$ 12,242,685	$ 813,447	$ 10,487,972	$ 30,668,248	$ 55,108,829	$ 14,754,838
	Operating Deductions									
16	Operations & Maintenance Expense		$ (137,825,696)	$ (101,413,575)	$ (3,814,219)	$ (97,156)	$ (1,947,787)	$ (12,252,352)	$ (8,975,128)	$ (3,409,915)
17	Incremental Uncollectible Expense		(110,019)	(101,881)	(3,975)	(11)	(1,797)	(1,508)	(718)	(44)
18	Administrative & General Expense	Total O&M	(93,808,967)	(69,025,609)	(2,596,090)	(66,128)	(1,325,732)	(8,339,377)	(6,108,784)	(2,320,907)
19	Depreciation Expense	Deprec Exp	(112,627,474)	(84,839,935)	(3,046,029)	(116,903)	(1,689,674)	(6,891,697)	(7,115,955)	(2,409,063)
20	Interest on Customer Deposits	8.0	(958,434)	(894,432)	(34,897)	(93)	(15,774)	(13,239)	0	0
21	Taxes Other Than Income	1.1	(58,155,759)	(44,248,792)	(1,605,870)	(57,875)	(883,291)	(3,549,509)	(3,516,701)	(1,193,212)
22	Total Operating Deductions		$ (403,486,349)	$ (300,524,225)	$ (11,101,079)	$ (338,165)	$ (5,864,054)	$ (31,047,682)	$ (25,717,286)	$ (9,333,141)
	State Income Tax									
23	Taxable Income before Interest Expense		$ 171,733,457	$ 106,083,421	$ 1,141,606	$ 475,282	$ 4,623,918	$ (379,434)	$ 29,391,543	$ 5,421,696
24	Interest Expense	1.1	(47,329,818)	(36,011,691)	(1,306,931)	(47,101)	(718,863)	(2,888,752)	(2,862,052)	(971,091)
25	Total State Taxable Income		$ 124,403,639	$ 70,071,730	$ (165,325)	$ 428,181	$ 3,905,056	$ (3,268,187)	$ 26,529,491	$ 4,450,606
26	State Income Tax	4.90%	$ 6,095,778	$ 3,433,515	$ (8,101)	$ 20,981	$ 191,348	$ (160,141)	$ 1,299,945	$ 218,080
27	Total State Income Tax		$ 6,095,778	$ 3,433,515	$ (8,101)	$ 20,981	$ 191,348	$ (160,141)	$ 1,299,945	$ 218,080
	Federal Income Tax									
28	Taxable Income before Interest Expense		$ 171,733,457	$ 106,083,421	$ 1,141,606	$ 475,282	$ 4,623,918	$ (379,434)	$ 29,391,543	$ 5,421,696
29	Interest Expense	1.1	(47,329,818)	(36,011,691)	(1,306,931)	(47,101)	(718,863)	(2,888,752)	(2,862,052)	(971,091)
30	Total Federal Taxable Income		$ 124,403,639	$ 70,071,730	$ (165,325)	$ 428,181	$ 3,905,056	$ (3,268,187)	$ 26,529,491	$ 4,450,606
31	Federal Income Tax	19.97%	$ 24,844,651	$ 13,994,025	$ (33,017)	$ 85,512	$ 779,879	$ (652,690)	$ 5,298,205	$ 888,830
32	South Georgia Federal	1.1	(15,458,159)	(11,761,601)	(426,850)	(15,383)	(234,784)	(943,481)	(934,761)	(317,163)
33	Total Federal Income Tax		$ 9,386,492	$ 2,232,424	$ (459,867)	$ 70,129	$ 545,095	$ (1,596,171)	$ 4,363,444	$ 571,667
34	Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
35	Net Income		$ 156,251,187	$ 100,417,483	$ 1,609,574	$ 384,173	$ 3,887,476	$ 1,376,878	$ 23,728,154	$ 4,631,949
36	Rate of Return on Rate Base		5.98%	5.12%	2.42%	13.84%	9.89%	0.84%	14.05%	8.09%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
CLASS COST OF SERVICE STUDY SUMMARY - PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor	Total Amount	Transportation Eligible General	Air Conditioning	Street Lighting	Compression on Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	Rate Base										
1	Total Direct Net Plant		$ 3,155,975,561	$ 143,806,650	$ 191,916	$ 92,628	$ 12,031,036	$ 12,688,864	$ 4,830,155	$ 5,680,457	1
2	Total Common Systems Allocable Net Plant		95,625,305	4,107,335	5,285	2,846	344,263	358,250	136,600	143,580	2
3	Cash Working Capital	1.1	(10,297,032)	(343,798)	(569)	(275)	(35,040)	(28,823)	(11,824)	(21,626)	3
4	Materials & Supplies	1.1	36,813,908	1,581,245	2,035	1,095	132,535	137,919	52,589	55,275	4
5	Prepayments	1.1	7,721,011	331,636	427	230	27,797	28,926	11,029	11,593	5
6	Other	1.1	0	0	0	0	0	0	0	0	6
7	Customer Deposits	8.0	(36,862,844)	0	0	(594)	(1,189)	(297)	(5,943)	(5,349)	7
8	Customer Advances	8.0	(41,613,406)	0	0	(671)	(1,342)	(335)	(6,709)	(6,038)	8
9	Deferred Taxes	1.1	(594,534,243)	(25,536,662)	(32,860)	(17,691)	(2,140,397)	(2,227,356)	(849,290)	(892,682)	9
10	Other	1.1	0	0	0	0	0	0	0	0	10
11	Total Rate Base		$ 2,612,828,261	$ 123,946,406	$ 166,234	$ 77,567	$ 10,357,663	$ 10,957,147	$ 4,156,607	$ 4,965,210	11
	Margin										
12	Net Operating Margin	Direct	$ 560,538,080	$ 34,237,803	$ 45,111	$ 9,771	$ 2,524,464	$ 2,602,984	$ 1,418,021	$ 3,382,369	12
13	Special Contract & Optional Margin	Net Op Margin	5,126,755	215,119	306	144	19,268	18,705	7,258	10,116	13
14	Other Revenue	Various	9,554,972	26,189	559	384	2,160	930	3,212	11,267	14
15	Total Revenue		$ 575,219,806	$ 34,479,112	$ 45,975	$ 10,300	$ 2,545,892	$ 2,622,619	$ 1,428,491	$ 3,403,752	15
	Operating Deductions										
16	Operations & Maintenance Expense		$ (137,825,696)	$ (4,601,731)	$ (7,612)	$ (3,687)	$ (469,014)	$ (385,795)	$ (158,266)	$ (289,459)	16
17	Incremental Uncollectible Expense		(110,019)	(21)	(2)	(6)	(8)	(3)	(7)	(39)	17
18	Administrative & General Expense	Total O&M	(93,808,967)	(3,132,098)	(5,181)	(2,510)	(319,227)	(262,586)	(107,721)	(197,016)	18
19	Depreciation Expense	Deprec Exp	(112,627,474)	(5,220,583)	(7,037)	(3,292)	(436,534)	(462,116)	(175,829)	(212,827)	19
20	Interest on Customer Deposits	8.0	(958,434)	0	0	0	0	0	0	0	20
21	Taxes Other Than Income	1.1	(58,155,759)	(2,497,928)	(3,214)	(1,731)	(209,368)	(217,874)	(83,075)	(87,320)	21
22	Total Operating Deductions		$ (403,486,349)	$ (15,452,362)	$ (23,046)	$ (11,226)	$ (1,434,151)	$ (1,328,374)	$ (524,898)	$ (786,661)	22
	State Income Tax										
23	Taxable Income before Interest Expense		$ 171,733,457	$ 19,026,750	$ 22,929	$ (926)	$ 1,111,741	$ 1,294,246	$ 903,592	$ 2,617,092	23
24	Interest Expense	1.1	(47,329,818)	(2,032,928)	(2,616)	(1,408)	(170,393)	(177,316)	(67,610)	(71,065)	24
25	Total State Taxable Income		$ 124,403,639	$ 16,993,822	$ 20,313	$ (2,334)	$ 941,348	$ 1,116,930	$ 835,982	$ 2,546,027	25
26	State Income Tax	4.90%	$ 6,095,778	$ 832,697	$ 995	$ (114)	$ 46,126	$ 54,730	$ 40,963	$ 124,755	26
27	Total State Income Tax		$ 6,095,778	$ 832,697	$ 995	$ (114)	$ 46,126	$ 54,730	$ 40,963	$ 124,755	27
	Federal Income Tax										
28	Taxable Income before Interest Expense		$ 171,733,457	$ 19,026,750	$ 22,929	$ (926)	$ 1,111,741	$ 1,294,246	$ 903,592	$ 2,617,092	28
29	Interest Expense	1.1	(47,329,818)	(2,032,928)	(2,616)	(1,408)	(170,393)	(177,316)	(67,610)	(71,065)	29
30	Total Federal Taxable Income		$ 124,403,639	$ 16,993,822	$ 20,313	$ (2,334)	$ 941,348	$ 1,116,930	$ 835,982	$ 2,546,027	30
31	Federal Income Tax	19.97%	$ 24,844,651	$ 3,393,836	$ 4,057	$ (466)	$ 187,997	$ 223,062	$ 166,954	$ 508,467	31
32	South Georgia Federal	1.1	(15,458,159)	(663,965)	(854)	(460)	(55,651)	(57,912)	(22,082)	(23,210)	32
33	Total Federal Income Tax		$ 9,386,492	$ 2,729,871	$ 3,202	$ (926)	$ 132,345	$ 165,150	$ 144,872	$ 485,257	33
34	Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	34
35	Net Income		$ 156,251,187	$ 15,464,181	$ 18,731	$ 115	$ 933,270	$ 1,074,366	$ 717,757	$ 2,007,079	35
36	Rate of Return on Rate Base		5.98%	12.48%	11.27%	0.15%	9.01%	9.81%	17.27%	40.42%	36

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Single-Family Residential Demand	Single-Family Residential Customer	Single-Family Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 8,572	$ 23,822	$ 59
2	302.00	Franchises & Consents	1.1	1,167,977	234,731	652,329	1,615
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 243,303	$ 676,151	$ 1,674
5		Allocation Percentage	Intang. Plant	100%	20.10%	1	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 930,232	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	39,986,871	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 40,917,103	$ 0	$ 0
		Allocation Percentage		100%	52%	0.00%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 241,730	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	1,389,713	0	0
15	375.00	Structures	1.0	457,330	272,516	0	0
16	376.00	Mains - Demand	1.0	953,764,290	568,332,591	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	883,219,063	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	19,591,082	30,445,583	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	548,898,688	0
21	381.00	Meters	6.0	305,766,590	0	176,440,035	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	4,058,981
23	387.00	Other Equipment	1.0	(92,997)	(55,415)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 589,772,216	$ 1,639,003,369	$ 4,058,981
25		Allocation Percentage	Net Dist Plant	100.00%	20.10%	55.85%	0.14%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 28,578,154	$ 79,419,968	$ 196,683
27		Total Direct Net Plant		$ 3,155,975,561	$ 659,510,776	$ 1,719,099,488	$ 4,257,338
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 8,187,597	$ 22,753,699	$ 56,349
29	389-398	Total Common General Plant	1.1	54,885,400	11,030,451	30,654,118	75,915
30		Total Systems Allocable		$ 95,625,305	$ 19,218,049	$ 53,407,816	$ 132,264
31		Total Net Plant		$ 3,251,600,867	$ 678,728,825	$ 1,772,507,304	$ 4,389,602
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (1,124,339)	$ (6,372,635)	$ (79,689)
33		Materials & Supplies	1.1	36,813,908	7,398,580	20,560,985	50,919
34		Prepayments	1.1	7,721,011	1,551,710	4,312,272	10,679
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(32,667,363)	0
37		Customer Advances	9.0	(41,613,406)	0	(36,877,248)	0
38		Deferred Taxes	1.1	(594,534,243)	(119,484,982)	(332,054,111)	(822,330)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 567,069,794	$ 1,389,409,204	$ 3,549,182

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 145	$ 1,032	$ 1
2	302.00	Franchises & Consents	1.1	1,167,977	3,963	28,252	37
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 4,107	$ 29,284	$ 38
5		Allocation Percentage	Intang. Plant	100%	0	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 17,613	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	757,108	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 774,721	$ 0	$ 0
		Allocation Percentage		100%	0.99%	0.00%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 4,081	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	23,461	0	0
15	375.00	Structures	1.0	457,330	4,601	0	0
16	376.00	Mains - Demand	1.0	953,764,290	9,594,632	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	34,459,050	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	330,738	1,187,843	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	28,454,113	0
21	381.00	Meters	6.0	305,766,590	0	6,883,860	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	92,249
23	387.00	Other Equipment	1.0	(92,997)	(936)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 9,956,577	$ 70,984,866	$ 92,249
25		Allocation Percentage	Net Dist Plant	100.00%	0.34%	2.42%	0.00%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 482,458	$ 3,439,661	$ 4,470
27		Total Direct Net Plant		$ 3,155,975,561	$ 11,217,865	$ 74,453,811	$ 96,757
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 138,224	$ 985,458	$ 1,281
29	389-398	Total Common General Plant	1.1	54,885,400	186,217	1,327,623	1,725
30		Total Systems Allocable		$ 95,625,305	$ 324,440	$ 2,313,080	$ 3,006
31		Total Net Plant		$ 3,251,600,867	$ 11,542,305	$ 76,766,891	$ 99,763
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (19,099)	$ (264,052)	$ (1,811)
33		Materials & Supplies	1.1	36,813,908	124,903	890,492	1,157
34		Prepayments	1.1	7,721,011	26,196	186,764	243
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(3,007,397)	0
37		Customer Advances	9.0	(41,613,406)	0	(3,394,964)	0
38		Deferred Taxes	1.1	(594,534,243)	(2,017,154)	(14,381,189)	(18,689)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 9,657,151	$ 56,796,545	$ 80,663

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Master-Metered Mobile Home Park Demand	Master-Metered Mobile Home Park Customer	Master-Metered Mobile Home Park Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 38	$ 4	$ 0
2	302.00	Franchises & Consents	1.1	1,167,977	1,044	111	8
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 1,082	$ 115	$ 8
5		Allocation Percentage	Intang. Plant	100%	0	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 4,125	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	177,305	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 181,429	$ 0	$ 0
		Allocation Percentage		100%	0%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 1,075	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	6,180	0	0
15	375.00	Structures	1.0	457,330	1,212	0	0
16	376.00	Mains - Demand	1.0	953,764,290	2,527,246	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	91,574	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	87,117	3,157	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	41,474	0
21	381.00	Meters	6.0	305,766,590	0	141,690	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	19,937
23	387.00	Other Equipment	1.0	(92,997)	(246)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 2,622,583	$ 277,894	$ 19,937
25		Allocation Percentage	Net Dist Plant	100.00%	0.09%	0.01%	0.00%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 127,081	$ 13,466	$ 966
27		Total Direct Net Plant		$ 3,155,975,561	$ 2,932,175	$ 291,475	$ 20,911
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 36,408	$ 3,858	$ 277
29	389-398	Total Common General Plant	1.1	54,885,400	49,050	5,197	373
30		Total Systems Allocable		$ 95,625,305	$ 85,458	$ 9,055	$ 650
31		Total Net Plant		$ 3,251,600,867	$ 3,017,633	$ 300,530	$ 21,560
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (4,999)	$ (1,868)	$ (391)
33		Materials & Supplies	1.1	36,813,908	32,900	3,486	250
34		Prepayments	1.1	7,721,011	6,900	731	52
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(4,457)	0
37		Customer Advances	9.0	(41,613,406)	0	(5,032)	0
38		Deferred Taxes	1.1	(594,534,243)	(531,323)	(56,300)	(4,039)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 2,521,112	$ 237,090	$ 17,433

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Demand	Small General Customer	Small General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 159	$ 488	$ 1
2	302.00	Franchises & Consents	1.1	1,167,977	4,346	13,369	25
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 4,505	$ 13,857	$ 26
5		Allocation Percentage	Intang. Plant	100%	0	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 16,662	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	716,232	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 732,894	$ 0	$ 0
		Allocation Percentage		100%	1%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 4,476	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	25,730	0	0
15	375.00	Structures	1.0	457,330	5,046	0	0
16	376.00	Mains - Demand	1.0	953,764,290	10,522,449	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	15,576,093	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	362,721	536,926	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	14,365,148	0
21	381.00	Meters	6.0	305,766,590	0	3,111,625	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	62,479
23	387.00	Other Equipment	1.0	(92,997)	(1,026)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 10,919,395	$ 33,589,792	$ 62,479
25		Allocation Percentage	Net Dist Plant	100.00%	0.37%	1.14%	0.00%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 529,113	$ 1,627,636	$ 3,028
27		Total Direct Net Plant		$ 3,155,975,561	$ 12,185,906	$ 35,231,285	$ 65,533
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 151,590	$ 466,315	$ 867
29	389-398	Total Common General Plant	1.1	54,885,400	204,224	628,227	1,169
30		Total Systems Allocable		$ 95,625,305	$ 355,814	$ 1,094,542	$ 2,036
31		Total Net Plant		$ 3,251,600,867	$ 12,541,720	$ 36,325,826	$ 67,568
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (20,782)	$ (123,512)	$ (1,227)
33		Materials & Supplies	1.1	36,813,908	136,982	421,378	784
34		Prepayments	1.1	7,721,011	28,729	88,376	164
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(521,720)	0
37		Customer Advances	9.0	(41,613,406)	0	(588,954)	0
38		Deferred Taxes	1.1	(594,534,243)	(2,212,216)	(6,805,128)	(12,658)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 10,474,433	$ 28,796,265	$ 54,632

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Demand	Medium General Customer	Medium General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 897	$ 1,697	$ 10
2	302.00	Franchises & Consents	1.1	1,167,977	24,566	46,459	262
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 25,463	$ 48,156	$ 271
5		Allocation Percentage	Intang. Plant	100%	0	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 116,782	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	5,019,971	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 5,136,752	$ 0	$ 0
		Allocation Percentage		100%	7%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 25,298	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	145,442	0	0
15	375.00	Structures	1.0	457,330	28,520	0	0
16	376.00	Mains - Demand	1.0	953,764,290	59,479,346	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	13,072,703	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	2,050,322	450,631	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	40,199,254	0
21	381.00	Meters	6.0	305,766,590	0	63,008,225	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	657,511
23	387.00	Other Equipment	1.0	(92,997)	(5,800)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 61,723,129	$ 116,730,814	$ 657,511
25		Allocation Percentage	Net Dist Plant	100.00%	2.10%	3.98%	0.02%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 2,990,872	$ 5,656,338	$ 31,861
27		Total Direct Net Plant		$ 3,155,975,561	$ 69,876,216	$ 122,435,308	$ 689,643
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 856,880	$ 1,620,532	$ 9,128
29	389-398	Total Common General Plant	1.1	54,885,400	1,154,402	2,183,205	12,297
30		Total Systems Allocable		$ 95,625,305	$ 2,011,282	$ 3,803,737	$ 21,425
31		Total Net Plant		$ 3,251,600,867	$ 71,887,498	$ 126,239,045	$ 711,069
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (118,872)	$ (783,599)	$ (12,909)
33		Materials & Supplies	1.1	36,813,908	774,305	1,464,366	8,248
34		Prepayments	1.1	7,721,011	162,396	307,123	1,730
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(470,236)	0
37		Customer Advances	9.0	(41,613,406)	0	(530,836)	0
38		Deferred Taxes	1.1	(594,534,243)	(12,504,806)	(23,649,095)	(133,209)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 60,200,520	$ 102,576,767	$ 574,929

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large-1 General Demand	Large-1 General Customer	Large-1 General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 1,904	$ 653	$ 23
2	302.00	Franchises & Consents	1.1	1,167,977	52,134	17,872	621
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 54,038	$ 18,525	$ 644
5		Allocation Percentage	Intang. Plant	100%	4.46%	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 256,731	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	11,035,827	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 11,292,558	$ 0	$ 0
		Allocation Percentage		100%	14%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 53,689	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	308,658	0	0
15	375.00	Structures	1.0	457,330	60,526	0	0
16	376.00	Mains - Demand	1.0	953,764,290	126,227,980	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	6,227,106	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	4,351,225	214,656	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	5,667,948	0
21	381.00	Meters	6.0	305,766,590	0	32,794,963	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	1,561,486
23	387.00	Other Equipment	1.0	(92,997)	(12,308)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 130,989,770	$ 44,904,673	$ 1,561,486
25		Allocation Percentage	Net Dist Plant	100.00%	4.46%	1.53%	0.05%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 6,347,274	$ 2,175,912	$ 75,664
27		Total Direct Net Plant		$ 3,155,975,561	$ 148,683,640	$ 47,099,110	$ 1,637,794
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 1,818,484	$ 623,396	$ 21,678
29	389-398	Total Common General Plant	1.1	54,885,400	2,449,889	839,848	29,204
30		Total Systems Allocable		$ 95,625,305	$ 4,268,373	$ 1,463,243	$ 50,882
31		Total Net Plant		$ 3,251,600,867	$ 152,952,013	$ 48,562,353	$ 1,688,676
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (252,824)	$ (387,056)	$ (30,656)
33		Materials & Supplies	1.1	36,813,908	1,643,242	563,321	19,589
34		Prepayments	1.1	7,721,011	344,638	118,146	4,108
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(167,303)	0
37		Customer Advances	9.0	(41,613,406)	0	(188,864)	0
38		Deferred Taxes	1.1	(594,534,243)	(26,537,890)	(9,097,468)	(316,349)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 128,149,179	$ 39,403,128	$ 1,365,367

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large-2 General Demand	Large-2 General Customer	Large-2 General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 605	$ 262	$ 8
2	302.00	Franchises & Consents	1.1	1,167,977	16,570	7,183	211
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 17,175	$ 7,445	$ 219
5		Allocation Percentage	Intang. Plant	100%	0	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 84,478	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	3,631,359	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 3,715,836	$ 0	$ 0
		Allocation Percentage		100%	5%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 17,064	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	98,101	0	0
15	375.00	Structures	1.0	457,330	19,237	0	0
16	376.00	Mains - Demand	1.0	953,764,290	40,119,153	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	382,732	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	1,382,954	13,193	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	3,140,415	0
21	381.00	Meters	6.0	305,766,590	0	14,510,693	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	530,939
23	387.00	Other Equipment	1.0	(92,997)	(3,912)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 41,632,597	$ 18,047,034	$ 530,939
25		Allocation Percentage	Net Dist Plant	100.00%	1.42%	0.61%	0.02%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 2,017,360	$ 874,492	$ 25,727
27		Total Direct Net Plant		$ 3,155,975,561	$ 47,382,969	$ 18,928,971	$ 556,886
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 577,970	$ 250,541	$ 7,371
29	389-398	Total Common General Plant	1.1	54,885,400	778,650	337,532	9,930
30		Total Systems Allocable		$ 95,625,305	$ 1,356,621	$ 588,072	$ 17,301
31		Total Net Plant		$ 3,251,600,867	$ 48,739,589	$ 19,517,043	$ 574,187
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (80,534)	$ (163,799)	$ (10,424)
33		Materials & Supplies	1.1	36,813,908	522,273	226,397	6,661
34		Prepayments	1.1	7,721,011	109,537	47,482	1,397
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(10,995)	0
37		Customer Advances	9.0	(41,613,406)	0	(12,412)	0
38		Deferred Taxes	1.1	(594,534,243)	(8,434,562)	(3,656,241)	(107,566)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 40,856,304	$ 15,947,475	$ 464,255

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible General Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 1,703	$ 104	$ 25
2	302.00	Franchises & Consents	1.1	1,167,977	46,633	2,848	686
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 48,336	$ 2,952	$ 711
5		Allocation Percentage	Intang. Plant	100%	0	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 263,700	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	11,335,396	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 11,599,096	$ 0	$ 0
		Allocation Percentage		100%	15%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 48,024	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	276,090	0	0
15	375.00	Structures	1.0	457,330	54,140	0	0
16	376.00	Mains - Demand	1.0	953,764,290	112,908,833	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	177,865	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	3,892,098	6,131	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	807,741	0
21	381.00	Meters	6.0	305,766,590	0	6,163,669	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	1,724,171
23	387.00	Other Equipment	1.0	(92,997)	(11,009)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 117,168,175	$ 7,155,405	$ 1,724,171
25		Allocation Percentage	Net Dist Plant	100.00%	3.99%	0.24%	0.06%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 5,677,531	$ 346,724	$ 83,547
27		Total Direct Net Plant		$ 3,155,975,561	$ 134,493,139	$ 7,505,081	$ 1,808,430
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 1,626,604	$ 99,336	$ 23,936
29	389-398	Total Common General Plant	1.1	54,885,400	2,191,385	133,827	32,247
30		Total Systems Allocable		$ 95,625,305	$ 3,817,989	$ 233,163	$ 56,183
31		Total Net Plant		$ 3,251,600,867	$ 138,311,128	$ 7,738,244	$ 1,864,613
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (228,257)	$ (81,690)	$ (33,850)
33		Materials & Supplies	1.1	36,813,908	1,469,852	89,763	21,629
34		Prepayments	1.1	7,721,011	308,273	18,826	4,536
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	0	0
37		Customer Advances	9.0	(41,613,406)	0	0	0
38		Deferred Taxes	1.1	(594,534,243)	(23,737,702)	(1,449,650)	(349,309)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 116,123,294	$ 6,315,493	$ 1,507,619

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air Conditioning Demand	Air Conditioning Customer	Air Conditioning Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 2	$ 0	$ 0
2	302.00	Franchises & Consents	1.1	1,167,977	52	11	1
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 54	$ 12	$ 1
5		Allocation Percentage	Intang. Plant	100%	0	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 496	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	21,300	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 21,796	$ 0	$ 0
		Allocation Percentage		100%	0%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 54	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	309	0	0
15	375.00	Structures	1.0	457,330	61	0	0
16	376.00	Mains - Demand	1.0	953,764,290	126,186	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	16,730	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	4,350	577	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	7,335	0
21	381.00	Meters	6.0	305,766,590	0	3,342	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	3,264
23	387.00	Other Equipment	1.0	(92,997)	(12)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 130,946	$ 27,984	$ 3,264
25		Allocation Percentage	Net Dist Plant	100.00%	0.00%	0.00%	0.00%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 6,345	$ 1,356	$ 158
27		Total Direct Net Plant		$ 3,155,975,561	$ 159,141	$ 29,351	$ 3,424
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 1,818	$ 388	$ 45
29	389-398	Total Common General Plant	1.1	54,885,400	2,449	523	61
30		Total Systems Allocable		$ 95,625,305	$ 4,267	$ 912	$ 106
31		Total Net Plant		$ 3,251,600,867	$ 163,408	$ 30,263	$ 3,530
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (268)	$ (237)	$ (64)
33		Materials & Supplies	1.1	36,813,908	1,643	351	41
34		Prepayments	1.1	7,721,011	345	74	9
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	0	0
37		Customer Advances	9.0	(41,613,406)	0	0	0
38		Deferred Taxes	1.1	(594,534,243)	(26,529)	(5,669)	(661)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 138,599	$ 24,781	$ 2,854

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Demand	Street Lighting Customer	Street Lighting Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 0	$ 1	$ 0
2	302.00	Franchises & Consents	1.1	1,167,977	4	31	0
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 4	$ 32	$ 0
5		Allocation Percentage	Intang. Plant	100%	0	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 24	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	1,013	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 1,036	$ 0	$ 0
		Allocation Percentage		100%	0%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 4	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	21	0	0
15	375.00	Structures	1.0	457,330	4	0	0
16	376.00	Mains - Demand	1.0	953,764,290	8,595	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	52,831	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	296	1,821	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	23,594	0
21	381.00	Meters	6.0	305,766,590	0	0	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	159
23	387.00	Other Equipment	1.0	(92,997)	(1)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 8,919	$ 78,247	$ 159
25		Allocation Percentage	Net Dist Plant	100.00%	0.00%	0.00%	0.00%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 432	$ 3,792	$ 8
27		Total Direct Net Plant		$ 3,155,975,561	$ 10,391	$ 82,070	$ 166
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 124	$ 1,086	$ 2
29	389-398	Total Common General Plant	1.1	54,885,400	167	1,463	3
30		Total Systems Allocable		$ 95,625,305	$ 291	$ 2,550	$ 5
31		Total Net Plant		$ 3,251,600,867	$ 10,682	$ 84,620	$ 172
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (18)	$ (255)	$ (3)
33		Materials & Supplies	1.1	36,813,908	112	982	2
34		Prepayments	1.1	7,721,011	23	206	0
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(594)	0
37		Customer Advances	9.0	(41,613,406)	0	(671)	0
38		Deferred Taxes	1.1	(594,534,243)	(1,807)	(15,852)	(32)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 8,993	$ 68,435	$ 139

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line	Account		Allocation	Total	Compression on Customer's Premises		
No.	No.	Description	Factor No.	Amount	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 114	$ 37	$ 2
2	302.00	Franchises & Consents	1.1	1,167,977	3,122	1,025	58
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 3,236	$ 1,062	$ 60
5		Allocation Percentage	Intang. Plant	100%	0	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 21,594	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	928,251	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 949,846	$ 0	$ 0
		Allocation Percentage		100%	1%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 3,215	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	18,485	0	0
15	375.00	Structures	1.0	457,330	3,625	0	0
16	376.00	Mains - Demand	1.0	953,764,290	7,559,594	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	67,800	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	260,588	2,337	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	1,289,274	0
21	381.00	Meters	6.0	305,766,590	0	1,215,912	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	144,804
23	387.00	Other Equipment	1.0	(92,997)	(737)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 7,844,770	$ 2,575,323	$ 144,804
25		Allocation Percentage	Net Dist Plant	100.00%	0.27%	0.09%	0.00%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 380,128	$ 124,791	$ 7,017
27		Total Direct Net Plant		$ 3,155,975,561	$ 9,177,980	$ 2,701,176	$ 151,880
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 108,906	$ 35,752	$ 2,010
29	389-398	Total Common General Plant	1.1	54,885,400	146,720	48,166	2,708
30		Total Systems Allocable		$ 95,625,305	$ 255,626	$ 83,918	$ 4,719
31		Total Net Plant		$ 3,251,600,867	$ 9,433,606	$ 2,785,095	$ 156,599
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (15,527)	$ (16,671)	$ (2,843)
33		Materials & Supplies	1.1	36,813,908	98,411	32,307	1,817
34		Prepayments	1.1	7,721,011	20,640	6,776	381
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(1,189)	0
37		Customer Advances	9.0	(41,613,406)	0	(1,342)	0
38		Deferred Taxes	1.1	(594,534,243)	(1,589,312)	(521,748)	(29,337)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 7,947,818	$ 2,283,228	$ 126,617

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Demand	Electric Generation Customer	Electric Generation Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 151	$ 5	$ 3
2	302.00	Franchises & Consents	1.1	1,167,977	4,147	146	82
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 4,299	$ 152	$ 85
5		Allocation Percentage	Intang. Plant	100%	0.36%	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 26,315	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	1,131,155	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 1,157,469	$ 0	$ 0
		Allocation Percentage		100%	1%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 4,271	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	24,555	0	0
15	375.00	Structures	1.0	457,330	4,815	0	0
16	376.00	Mains - Demand	1.0	953,764,290	10,041,829	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	22,013	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	346,153	759	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	14,104	0
21	381.00	Meters	6.0	305,766,590	0	330,836	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	205,769
23	387.00	Other Equipment	1.0	(92,997)	(979)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 10,420,644	$ 367,712	$ 205,769
25		Allocation Percentage	Net Dist Plant	100.00%	0.36%	0.01%	0.01%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 504,945	$ 17,818	$ 9,971
27		Total Direct Net Plant		$ 3,155,975,561	$ 12,087,358	$ 385,682	$ 215,824
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 144,666	$ 5,105	$ 2,857
29	389-398	Total Common General Plant	1.1	54,885,400	194,896	6,877	3,848
30		Total Systems Allocable		$ 95,625,305	$ 339,562	$ 11,982	$ 6,705
31		Total Net Plant		$ 3,251,600,867	$ 12,426,920	$ 397,664	$ 222,529
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (20,478)	$ (4,305)	$ (4,040)
33		Materials & Supplies	1.1	36,813,908	130,725	4,613	2,581
34		Prepayments	1.1	7,721,011	27,417	967	541
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(297)	0
37		Customer Advances	9.0	(41,613,406)	0	(335)	0
38		Deferred Taxes	1.1	(594,534,243)	(2,111,172)	(74,497)	(41,688)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 10,453,413	$ 323,810	$ 179,925

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agricultural User Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 56	$ 4	$ 1
2	302.00	Franchises & Consents	1.1	1,167,977	1,532	112	24
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 1,588	$ 116	$ 25
5		Allocation Percentage	Intang. Plant	100%	0	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 9,850	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	423,391	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 433,241	$ 0	$ 0
		Allocation Percentage		100%	1%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 1,578	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	9,071	0	0
15	375.00	Structures	1.0	457,330	1,779	0	0
16	376.00	Mains - Demand	1.0	953,764,290	3,709,732	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	64,131	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	127,879	2,211	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	27,960	0
21	381.00	Meters	6.0	305,766,590	0	186,854	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	61,221
23	387.00	Other Equipment	1.0	(92,997)	(362)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 3,849,677	$ 281,156	$ 61,221
25		Allocation Percentage	Net Dist Plant	100.00%	0.13%	0.01%	0.00%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 186,541	$ 13,624	$ 2,967
27		Total Direct Net Plant		$ 3,155,975,561	$ 4,471,047	$ 294,895	$ 64,213
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 53,444	$ 3,903	$ 850
29	389-398	Total Common General Plant	1.1	54,885,400	72,000	5,258	1,145
30		Total Systems Allocable		$ 95,625,305	$ 125,444	$ 9,162	$ 1,995
31		Total Net Plant		$ 3,251,600,867	$ 4,596,490	$ 304,057	$ 66,208
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (7,573)	$ (3,049)	$ (1,202)
33		Materials & Supplies	1.1	36,813,908	48,293	3,527	768
34		Prepayments	1.1	7,721,011	10,129	740	161
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(5,943)	0
37		Customer Advances	9.0	(41,613,406)	0	(6,709)	0
38		Deferred Taxes	1.1	(594,534,243)	(779,926)	(56,961)	(12,403)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 3,867,414	$ 235,661	$ 53,532

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
RATE BASE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Cost of Service					
		Direct					
		Intangible Plant					
1	301.00	Organization	1.1	$ 42,653	$ 39	$ 22	$ 3
2	302.00	Franchises & Consents	1.1	1,167,977	1,076	602	76
3	303.00	Miscellaneous Intangible Plant	1.1	0	0	0	0
4		Total Direct Intangible Plant		$ 1,210,630	$ 1,116	$ 624	$ 78
5		Allocation Percentage	Intang. Plant	100%	0	0	0
		Storage Plant					
6	360.00	Land and Land Rights	2.0	$ 1,772,673	$ 24,073	$ 0	$ 0
7	361.00	Structures and Improvements	2.0	76,200,000	1,034,821	0	0
8	363.10	Liquifaction Equipment	2.0	0	0	0	0
9	363.20	Vaporizing Equipment	2.0	0	0	0	0
10	363.30	Compressor Equipment	2.0	0	0	0	0
11	363.50	Other Equipment	2.0	0	0	0	0
12		Total Storage Plant		$ 77,972,673	$ 1,058,895	$ 0	$ 0
		Allocation Percentage		100%	1%	0%	0%
		Distribution Plant					
13	374.10	Land & Land Rights	1.0	$ 405,666	$ 1,108	$ 0	$ 0
14	374.20	Rights of Way	1.0	2,332,188	6,373	0	0
15	375.00	Structures	1.0	457,330	1,250	0	0
16	376.00	Mains - Demand	1.0	953,764,290	2,606,124	0	0
17	376.00	Mains - Customer	5.0	953,764,290	0	334,597	0
18	378.00	Measuring & Regulating Station	2.2	65,754,717	89,836	11,534	0
19	380.00	Services - Demand	1.0	0	0	0	0
20	380.00	Services - Customer	7.0	643,127,744	0	190,694	0
21	381.00	Meters	6.0	305,766,590	0	974,888	0
22	385.00	Industrial Measuring & Regulating Station	3.0	9,313,055	0	0	190,084
23	387.00	Other Equipment	1.0	(92,997)	(254)	0	0
24		Total Direct Distribution Plant		$ 2,934,592,871	$ 2,704,437	$ 1,511,714	$ 190,084
25		Allocation Percentage	Net Dist Plant	100.00%	0.09%	0.05%	0.01%
26	389-398	Total Direct General Plant	1.1	$ 142,199,386	$ 131,047	$ 73,252	$ 9,211
27		Total Direct Net Plant		$ 3,155,975,561	$ 3,895,494	$ 1,585,589	$ 199,374
		Common - Systems Allocable					
28	301-303	Total Common Intangible Plant	1.1	$ 40,739,905	$ 37,545	$ 20,987	$ 2,639
29	389-398	Total Common General Plant	1.1	54,885,400	50,581	28,273	3,555
30		Total Systems Allocable		$ 95,625,305	$ 88,126	$ 49,260	$ 6,194
31		Total Net Plant		$ 3,251,600,867	$ 3,983,619	$ 1,634,849	$ 205,568
		Other Rate Base Items					
32		Cash Working Capital	11.2	$ (10,297,032)	$ (6,383)	$ (11,511)	$ (3,732)
33		Materials & Supplies	1.1	36,813,908	33,927	18,964	2,385
34		Prepayments	1.1	7,721,011	7,115	3,977	500
35		Other	1.1	0	0	0	0
36		Customer Deposits	9.0	(36,862,844)	0	(5,349)	0
37		Customer Advances	9.0	(41,613,406)	0	(6,038)	0
38		Deferred Taxes	1.1	(594,534,243)	(547,906)	(306,266)	(38,510)
39		Other	1.1	0	0	0	0
40		Total Allocated Rate Base		$ 2,612,828,261	$ 3,470,373	$ 1,328,627	$ 166,210

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Single-Family Residential Demand	Single-Family Residential Customer	Single-Family Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 14,426	$ 40,089	$ 99
2	360 - 363.50	Storage Plant	2.0	3,619,500	1,899,376	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	17,053,919	47,393,603	117,370
4	389 - 398	General Plant	1.1	12,828,977	2,578,270	7,165,129	17,744
5		Total Direct Depreciation Expense		$ 101,377,269	$ 21,545,991	$ 54,598,821	$ 135,214
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 2,038,373	$ 5,664,730	$ 14,029
7		General Plant	1.1	4,536,929	911,797	2,533,926	6,275
8		Total System Allocable Amortization		$ 14,679,481	$ 2,950,171	$ 8,198,656	$ 20,304
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 911,797	$ 2,533,926	$ 6,275
10		Total Depreciation Expense		$ 116,056,749	$ 24,496,162	$ 62,797,478	$ 155,518
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(2,926,828)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (689,190)	$ (1,915,289)	$ (4,743)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 23,806,972	$ 60,882,189	$ 150,774
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	591,932
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 591,932
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 771,446	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 911,000	$ 5,551,461	$ 75,600
22		Materials & Expenses	5.5	1,448,039	131,808	803,212	10,938
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	225,800
24		Materials & Expenses	3.0	157,480	0	0	68,636
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	1,031,491	2,599,211	0
26		Materials & Expenses	4.4	7,944,286	1,770,131	4,460,481	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	538,264	836,491	0
28		Materials & Expenses	2.2	698,517	208,118	323,426	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	4,366,039	0
30		Materials & Expenses	6.0	3,177,057	0	1,833,294	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	6,164,331	0
32		Materials & Expenses	6.0	1,798,117	0	1,037,588	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	595,507	3,628,907	49,419
34		Materials & Expenses	5.5	6,591,122	599,957	3,656,024	49,788
35	881.00	Rents	5.5	(724,435)	(65,942)	(401,836)	(5,472)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 5,720,334	$ 34,858,629	$ 474,709
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 6,491,780	$ 34,858,629	$ 1,066,641

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Single-Family Residential Demand	Single-Family Residential Customer	Single-Family Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 417,483	$ 1,329,917	$ 0
2		Materials & Expenses	6.6	264,999	48,985	156,046	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	15,381	0	0
4		Materials & Expenses	1.0	53,126	31,657	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	3,441,096	5,347,645	0
6		Materials & Expenses	2.2	12,648,532	3,768,527	5,856,491	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	549,167	853,434	0
8		Materials & Expenses	2.2	733,457	218,528	339,603	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	4,965,204	0
10		Materials & Expenses	3.3	7,070,213	0	6,034,308	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	1,402,026	0
12		Materials & Expenses	6.0	1,063,225	0	613,525	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	53,112	169,192	0
14		Materials & Expenses	6.6	73,309	13,551	43,168	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 8,557,486	$ 27,110,560	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 15,049,267	$ 61,969,188	$ 1,066,641
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 1,415,138	$ 0
18		Materials & Expenses	10.1	262,816	0	235,372	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	1,141,810	0
20		Materials & Expenses	11.0	324,290	0	300,304	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	6,533,369	0
22		Materials & Expenses	4.0	12,941,582	0	11,984,357	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	0	0
24		Materials & Expenses - KAM	15.0	2,968	0	0	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	1,250,818	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	107,518	0
27		Materials & Expenses	10.1	1,641	0	1,469	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 22,970,154	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(20)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	351,326	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 351,307	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	7,018	0
42		Total Sales Expense		$ 7,579	$ 0	$ 7,018	$ 0
43		Total O & M Expense		$ 137,825,696	$ 15,049,267	$ 85,297,667	$ 1,066,641
44		Allocation Percentage	Total O&M	1	0	1	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Single-Family Residential Demand	Single-Family Residential Customer	Single-Family Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 10,243,055	$ 58,056,562	$ 725,993
2		Interest on Customer Deposits	8.0	958,434	0	894,432	0
3		Taxes Other Than Income	1.1	58,155,759	11,687,703	32,480,650	80,438
4		Total Allocated Operating Deductions		$ 290,748,856	$ 36,980,025	$ 176,729,312	$ 1,873,072
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 9,511,988	$ 26,434,239	$ 65,464
6		South Georgia - Federal	1.1	(15,458,159)	(3,106,663)	(8,633,557)	(21,381)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 659,510,776	$ 1,719,099,488	$ 4,257,338
8		Total Common Systems Allocable Net Plant		95,625,305	19,218,049	53,407,816	132,264
9		Cash Working Capital	1.1	(10,297,032)	(1,124,339)	(6,372,635)	(79,689)
10		Materials & Supplies	1.1	36,813,908	7,398,580	20,560,985	50,919
11		Prepayments	1.1	7,721,011	1,551,710	4,312,272	10,679
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(32,667,363)	0
14		Customer Advances	9.0	(41,613,406)	0	(36,877,248)	0
15		Deferred Taxes	1.1	(594,534,243)	(119,484,982)	(332,054,111)	(822,330)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 567,069,794	$ 1,389,409,204	$ 3,549,182
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 206,220,445	$ 128,793,685	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	2,134,079	1,332,826	0
20		Late Charges	12.0	1,615,145	0	1,290,032	0
21		Service Establishment Charges	9.0	7,218,698	0	6,397,114	0
22		Reconnect / Reread Charges	9.0	224,248	0	198,726	0
23		Other Revenue - Labor	Net Op Margin	4,325	1,843	1,151	0
24		Other Revenue - Parts & Material	Net Op Margin	377	161	100	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(9)	(6)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	449,554	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	48,521	30,303	0
28		Total Revenue		$ 498,633,048	$ 208,405,039	$ 138,493,485	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (15,049,267)	$ (85,297,667)	$ (1,066,641)
30		A & G	Total O&M	(93,808,967)	(10,243,055)	(58,056,562)	(725,993)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(23,806,972)	(60,882,189)	(150,774)
32		Interest on Customer Deposits	8.0	(958,434)	0	(894,432)	0
33		Taxes Other Than Income	1.1	(58,155,759)	(11,687,703)	(32,480,650)	(80,438)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 147,618,043	$ (99,118,015)	$ (2,023,846)
35		Interest Expense	1.1	(47,329,818)	(9,511,988)	(26,434,239)	(65,464)
36		State Taxable Income		$ 47,926,899	$ 138,106,055	$ (125,552,255)	$ (2,089,311)
37		State Income Tax	4.90%	$ 2,348,418	$ 6,767,197	$ (6,152,060)	$ (102,376)
38		Total State Income Tax		$ 2,348,418	$ 6,767,197	$ (6,152,060)	$ (102,376)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 147,618,043	$ (99,118,015)	$ (2,023,846)
40		Interest Expense	1.1	(47,329,818)	(9,511,988)	(26,434,239)	(65,464)
41		Federal Taxable Income		$ 47,926,899	$ 138,106,055	$ (125,552,255)	$ (2,089,311)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 27,581,160	$ (25,074,041)	$ (417,256)
43		South Georgia Federal	1.1	(15,458,159)	(3,106,663)	(8,633,557)	(21,381)
44		Total Federal Income Tax		$ (5,886,678)	$ 24,474,497	$ (33,707,598)	$ (438,637)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 116,376,349	$ (59,258,357)	$ (1,482,833)
47		Rate of Return on Rate Base		3.78%	20.52%	-4.27%	-42%
48		Rate of Return by Class Total				2.84%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 244	$ 1,736	$ 2
2	360 - 363.50	Storage Plant	2.0	3,619,500	35,963	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	287,905	2,052,606	2,667
4	389 - 398	General Plant	1.1	12,828,977	43,527	310,320	403
5		Total Direct Depreciation Expense		$ 101,377,269	$ 367,638	$ 2,364,663	$ 3,073
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 34,412	$ 245,338	$ 319
7		General Plant	1.1	4,536,929	15,393	109,744	143
8		Total System Allocable Amortization		$ 14,679,481	$ 49,805	$ 355,082	$ 461
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 15,393	$ 109,744	$ 143
10		Total Depreciation Expense		$ 116,056,749	$ 417,443	$ 2,719,745	$ 3,534
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(151,723)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (11,635)	$ (82,951)	$ (108)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 405,808	$ 2,636,794	$ 3,427
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	13,453
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 13,453
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 14,607	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 15,380	$ 225,501	$ 1,718
22		Materials & Expenses	5.5	1,448,039	2,225	32,627	249
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	5,132
24		Materials & Expenses	3.0	157,480	0	0	1,560
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	17,414	114,184	0
26		Materials & Expenses	4.4	7,944,286	29,883	195,950	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	9,087	32,636	0
28		Materials & Expenses	2.2	698,517	3,513	12,619	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	170,342	0
30		Materials & Expenses	6.0	3,177,057	0	71,527	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	240,503	0
32		Materials & Expenses	6.0	1,798,117	0	40,482	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	10,053	147,407	1,123
34		Materials & Expenses	5.5	6,591,122	10,129	148,508	1,132
35	881.00	Rents	5.5	(724,435)	(1,113)	(16,323)	(124)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 96,571	$ 1,415,961	$ 10,789
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 111,178	$ 1,415,961	$ 24,242

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 7,048	$ 59,269	$ 0
2		Materials & Expenses	6.6	264,999	827	6,954	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	260	0	0
4		Materials & Expenses	1.0	53,126	534	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	58,093	208,640	0
6		Materials & Expenses	2.2	12,648,532	63,621	228,493	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	9,271	33,297	0
8		Materials & Expenses	2.2	733,457	3,689	13,250	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	257,389	0
10		Materials & Expenses	3.3	7,070,213	0	312,810	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	54,700	0
12		Materials & Expenses	6.0	1,063,225	0	23,937	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	897	7,540	0
14		Materials & Expenses	6.6	73,309	229	1,924	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 144,468	$ 1,208,202	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 255,646	$ 2,624,164	$ 24,242
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 55,212	$ 0
18		Materials & Expenses	10.1	262,816	0	9,183	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	44,548	0
20		Materials & Expenses	11.0	324,290	0	11,716	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	254,901	0
22		Materials & Expenses	4.0	12,941,582	0	467,573	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	0	0
24		Materials & Expenses - KAM	15.0	2,968	0	0	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	48,801	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	4,195	0
27		Materials & Expenses	10.1	1,641	0	57	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 896,187	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(1)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	13,707	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 13,706	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	274	0
42		Total Sales Expense		$ 7,579	$ 0	$ 274	$ 0
43		Total O & M Expense		$ 137,825,696	$ 255,646	$ 3,534,331	$ 24,242
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 174,001	$ 2,405,589	$ 16,500
2		Interest on Customer Deposits	8.0	958,434	0	34,897	0
3		Taxes Other Than Income	1.1	58,155,759	197,313	1,406,730	1,828
4		Total Allocated Operating Deductions		$ 290,748,856	$ 626,960	$ 7,381,546	$ 42,570
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 160,582	$ 1,144,861	$ 1,488
6		South Georgia - Federal	1.1	(15,458,159)	(52,447)	(373,917)	(486)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 11,217,865	$ 74,453,811	$ 96,757
8		Total Common Systems Allocable Net Plant		95,625,305	324,440	2,313,080	3,006
9		Cash Working Capital	1.1	(10,297,032)	(19,099)	(264,052)	(1,811)
10		Materials & Supplies	1.1	36,813,908	124,903	890,492	1,157
11		Prepayments	1.1	7,721,011	26,196	186,764	243
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(3,007,397)	0
14		Customer Advances	9.0	(41,613,406)	0	(3,394,964)	0
15		Deferred Taxes	1.1	(594,534,243)	(2,017,154)	(14,381,189)	(18,689)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 9,657,151	$ 56,796,545	$ 80,663
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 4,863,769	$ 4,555,305	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	50,333	47,141	0
20		Late Charges	12.0	1,615,145	0	85,387	0
21		Service Establishment Charges	9.0	7,218,698	0	588,926	0
22		Reconnect / Reread Charges	9.0	224,248	0	18,295	0
23		Other Revenue - Labor	Net Op Margin	4,325	43	41	0
24		Other Revenue - Parts & Material	Net Op Margin	377	4	4	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(0)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	36,400	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	1,144	1,072	0
28		Total Revenue		$ 498,633,048	$ 4,915,293	$ 5,332,570	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (255,646)	$ (3,534,331)	$ (24,242)
30		A & G	Total O&M	(93,808,967)	(174,001)	(2,405,589)	(16,500)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(405,808)	(2,636,794)	(3,427)
32		Interest on Customer Deposits	8.0	(958,434)	0	(34,897)	0
33		Taxes Other Than Income	1.1	(58,155,759)	(197,313)	(1,406,730)	(1,828)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 3,882,525	$ (4,685,770)	$ (45,996)
35		Interest Expense	1.1	(47,329,818)	(160,582)	(1,144,861)	(1,488)
36		State Taxable Income		$ 47,926,899	$ 3,721,943	$ (5,830,631)	$ (47,484)
37		State Income Tax	4.90%	$ 2,348,418	$ 182,375	$ (285,701)	$ (2,327)
38		Total State Income Tax		$ 2,348,418	$ 182,375	$ (285,701)	$ (2,327)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 3,882,525	$ (4,685,770)	$ (45,996)
40		Interest Expense	1.1	(47,329,818)	(160,582)	(1,144,861)	(1,488)
41		Federal Taxable Income		$ 47,926,899	$ 3,721,943	$ (5,830,631)	$ (47,484)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 743,309	$ (1,164,435)	$ (9,483)
43		South Georgia Federal	1.1	(15,458,159)	(52,447)	(373,917)	(486)
44		Total Federal Income Tax		$ (5,886,678)	$ 690,862	$ (1,538,353)	$ (9,969)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 3,009,288	$ (2,861,717)	$ (33,701)
47		Rate of Return on Rate Base		3.78%	31.16%	-5.04%	-41.78%
48		Rate of Return by Class Total				0.17%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Master-Metered Mobile Home Park Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 64	$ 7	$ 0
2	360 - 363.50	Storage Plant	2.0	3,619,500	8,422	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	75,835	8,036	576
4	389 - 398	General Plant	1.1	12,828,977	11,465	1,215	87
5		Total Direct Depreciation Expense		$ 101,377,269	$ 95,786	$ 9,257	$ 664
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 9,064	$ 960	$ 69
7		General Plant	1.1	4,536,929	4,055	430	31
8		Total System Allocable Amortization		$ 14,679,481	$ 13,119	$ 1,390	$ 100
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 4,055	$ 430	$ 31
10		Total Depreciation Expense		$ 116,056,749	$ 108,905	$ 10,647	$ 764
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(221)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (3,065)	$ (325)	$ (23)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 105,840	$ 10,323	$ 741
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	2,907
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 2,907
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 3,421	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 4,051	$ 2,963	$ 371
22		Materials & Expenses	5.5	1,448,039	586	429	54
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	1,109
24		Materials & Expenses	3.0	157,480	0	0	337
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	4,587	241	0
26		Materials & Expenses	4.4	7,944,286	7,871	414	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	2,394	87	0
28		Materials & Expenses	2.2	698,517	925	34	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	3,506	0
30		Materials & Expenses	6.0	3,177,057	0	1,472	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	4,950	0
32		Materials & Expenses	6.0	1,798,117	0	833	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	2,648	1,937	243
34		Materials & Expenses	5.5	6,591,122	2,668	1,951	245
35	881.00	Rents	5.5	(724,435)	(293)	(214)	(27)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 25,437	$ 18,602	$ 2,332
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 28,858	$ 18,602	$ 5,239

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Master-Metered Mobile Home Park Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 1,856	$ 195	$ 0
2		Materials & Expenses	6.6	264,999	218	23	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	68	0	0
4		Materials & Expenses	1.0	53,126	141	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	15,302	554	0
6		Materials & Expenses	2.2	12,648,532	16,758	607	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	2,442	88	0
8		Materials & Expenses	2.2	733,457	972	35	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	375	0
10		Materials & Expenses	3.3	7,070,213	0	456	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	1,126	0
12		Materials & Expenses	6.0	1,063,225	0	493	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	236	25	0
14		Materials & Expenses	6.6	73,309	60	6	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 38,053	$ 3,985	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 66,911	$ 22,587	$ 5,239
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 147	$ 0
18		Materials & Expenses	10.1	262,816	0	24	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	118	0
20		Materials & Expenses	11.0	324,290	0	31	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	677	0
22		Materials & Expenses	4.0	12,941,582	0	1,243	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	0	0
24		Materials & Expenses - KAM	15.0	2,968	0	0	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	130	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	11	0
27		Materials & Expenses	10.1	1,641	0	0	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 2,382	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	36	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 36	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	1	0
42		Total Sales Expense		$ 7,579	$ 0	$ 1	$ 0
43		Total O & M Expense		$ 137,825,696	$ 66,911	$ 25,006	$ 5,239
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Master-Metered Mobile Home Park Demand	Master-Metered Mobile Home Park Customer	Master-Metered Mobile Home Park Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 45,542	$ 17,020	$ 3,566
2		Interest on Customer Deposits	8.0	958,434	0	93	0
3		Taxes Other Than Income	1.1	58,155,759	51,973	5,507	395
4		Total Allocated Operating Deductions		$ 290,748,856	$ 164,425	$ 47,625	$ 9,200
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 42,298	$ 4,482	$ 322
6		South Georgia - Federal	1.1	(15,458,159)	(13,815)	(1,464)	(105)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 2,932,175	$ 291,475	$ 20,911
8		Total Common Systems Allocable Net Plant		95,625,305	85,458	9,055	650
9		Cash Working Capital	1.1	(10,297,032)	(4,999)	(1,868)	(391)
10		Materials & Supplies	1.1	36,813,908	32,900	3,486	250
11		Prepayments	1.1	7,721,011	6,900	731	52
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(4,457)	0
14		Customer Advances	9.0	(41,613,406)	0	(5,032)	0
15		Deferred Taxes	1.1	(594,534,243)	(531,323)	(56,300)	(4,039)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 2,521,112	$ 237,090	$ 17,433
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 672,479	$ 82,368	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	6,959	852	0
20		Late Charges	12.0	1,615,145	0	383	0
21		Service Establishment Charges	9.0	7,218,698	0	873	0
22		Reconnect / Reread Charges	9.0	224,248	0	27	0
23		Other Revenue - Labor	Net Op Margin	4,325	6	1	0
24		Other Revenue - Parts & Material	Net Op Margin	377	1	0	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(0)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	14	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	158	19	0
28		Total Revenue		$ 498,633,048	$ 679,603	$ 84,537	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (66,911)	$ (25,006)	$ (5,239)
30		A & G	Total O&M	(93,808,967)	(45,542)	(17,020)	(3,566)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(105,840)	(10,323)	(741)
32		Interest on Customer Deposits	8.0	(958,434)	0	(93)	0
33		Taxes Other Than Income	1.1	(58,155,759)	(51,973)	(5,507)	(395)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 409,338	$ 26,589	$ (9,941)
35		Interest Expense	1.1	(47,329,818)	(42,298)	(4,482)	(322)
36		State Taxable Income		$ 47,926,899	$ 367,040	$ 22,107	$ (10,262)
37		State Income Tax	4.90%	$ 2,348,418	$ 17,985	$ 1,083	$ (503)
38		Total State Income Tax		$ 2,348,418	$ 17,985	$ 1,083	$ (503)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 409,338	$ 26,589	$ (9,941)
40		Interest Expense	1.1	(47,329,818)	(42,298)	(4,482)	(322)
41		Federal Taxable Income		$ 47,926,899	$ 367,040	$ 22,107	$ (10,262)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 73,302	$ 4,415	$ (2,049)
43		South Georgia Federal	1.1	(15,458,159)	(13,815)	(1,464)	(105)
44		Total Federal Income Tax		$ (5,886,678)	$ 59,487	$ 2,951	$ (2,154)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 331,866	$ 22,555	$ (7,283)
47		Rate of Return on Rate Base		3.78%	13.16%	9.51%	-41.78%
48		Rate of Return by Class Total				12.51%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Demand	Small General Customer	Small General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 267	$ 822	$ 2
2	360 - 363.50	Storage Plant	2.0	3,619,500	34,021	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	315,746	971,286	1,807
4	389 - 398	General Plant	1.1	12,828,977	47,736	146,842	273
5		Total Direct Depreciation Expense		$ 101,377,269	$ 397,770	$ 1,118,950	$ 2,081
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 37,740	$ 116,093	$ 216
7		General Plant	1.1	4,536,929	16,882	51,930	97
8		Total System Allocable Amortization		$ 14,679,481	$ 54,621	$ 168,024	$ 313
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 16,882	$ 51,930	$ 97
10		Total Depreciation Expense		$ 116,056,749	$ 452,391	$ 1,286,974	$ 2,394
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(76,598)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (12,760)	$ (39,252)	$ (73)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 439,631	$ 1,247,722	$ 2,321
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	9,112
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 9,112
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 13,818	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 16,867	$ 103,833	$ 1,164
22		Materials & Expenses	5.5	1,448,039	2,440	15,023	168
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	3,476
24		Materials & Expenses	3.0	157,480	0	0	1,056
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	19,098	54,342	0
26		Materials & Expenses	4.4	7,944,286	32,773	93,255	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	9,966	14,752	0
28		Materials & Expenses	2.2	698,517	3,853	5,704	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	76,998	0
30		Materials & Expenses	6.0	3,177,057	0	32,331	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	108,712	0
32		Materials & Expenses	6.0	1,798,117	0	18,298	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	11,026	67,874	761
34		Materials & Expenses	5.5	6,591,122	11,108	68,381	766
35	881.00	Rents	5.5	(724,435)	(1,221)	(7,516)	(84)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 105,910	$ 651,988	$ 7,307
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 119,728	$ 651,988	$ 16,419

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Demand	Small General Customer	Small General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 7,730	$ 28,367	$ 0
2		Materials & Expenses	6.6	264,999	907	3,328	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	285	0	0
4		Materials & Expenses	1.0	53,126	586	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	63,710	94,309	0
6		Materials & Expenses	2.2	12,648,532	69,773	103,283	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	10,168	15,051	0
8		Materials & Expenses	2.2	733,457	4,046	5,989	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	129,944	0
10		Materials & Expenses	3.3	7,070,213	0	157,923	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	24,726	0
12		Materials & Expenses	6.0	1,063,225	0	10,820	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	983	3,609	0
14		Materials & Expenses	6.6	73,309	251	921	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 158,438	$ 578,269	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 278,166	$ 1,230,257	$ 16,419
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 25,667	$ 0
18		Materials & Expenses	10.1	262,816	0	4,269	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	20,137	0
20		Materials & Expenses	11.0	324,290	0	5,296	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	115,220	0
22		Materials & Expenses	4.0	12,941,582	0	211,351	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	10,610	0
24		Materials & Expenses - KAM	15.0	2,968	0	41	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	22,059	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	1,950	0
27		Materials & Expenses	10.1	1,641	0	27	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 416,627	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	6,196	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 6,196	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	124	0
42		Total Sales Expense		$ 7,579	$ 0	$ 124	$ 0
43		Total O & M Expense		$ 137,825,696	$ 278,166	$ 1,653,202	$ 16,419
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Demand	Small General Customer	Small General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 189,329	$ 1,125,227	$ 11,175
2		Interest on Customer Deposits	8.0	958,434	0	15,774	0
3		Taxes Other Than Income	1.1	58,155,759	216,393	665,660	1,238
4		Total Allocated Operating Deductions		$ 290,748,856	$ 683,889	$ 3,459,863	$ 28,832
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 176,111	$ 541,744	$ 1,008
6		South Georgia - Federal	1.1	(15,458,159)	(57,519)	(176,936)	(329)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 12,185,906	$ 35,231,285	$ 65,533
8		Total Common Systems Allocable Net Plant		95,625,305	355,814	1,094,542	2,036
9		Cash Working Capital	1.1	(10,297,032)	(20,782)	(123,512)	(1,227)
10		Materials & Supplies	1.1	36,813,908	136,982	421,378	784
11		Prepayments	1.1	7,721,011	28,729	88,376	164
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(521,720)	0
14		Customer Advances	9.0	(41,613,406)	0	(588,954)	0
15		Deferred Taxes	1.1	(594,534,243)	(2,212,216)	(6,805,128)	(12,658)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 10,474,433	$ 28,796,265	$ 54,632
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 3,480,428	$ 5,837,590	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	36,017	60,410	0
20		Late Charges	12.0	1,615,145	0	17,255	0
21		Service Establishment Charges	9.0	7,218,698	0	102,166	0
22		Reconnect / Reread Charges	9.0	224,248	0	3,174	0
23		Other Revenue - Labor	Net Op Margin	4,325	31	52	0
24		Other Revenue - Parts & Material	Net Op Margin	377	3	5	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(0)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	3,178	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	819	1,374	0
28		Total Revenue		$ 498,633,048	$ 3,517,298	$ 6,025,204	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (278,166)	$ (1,653,202)	$ (16,419)
30		A & G	Total O&M	(93,808,967)	(189,329)	(1,125,227)	(11,175)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(439,631)	(1,247,722)	(2,321)
32		Interest on Customer Deposits	8.0	(958,434)	0	(15,774)	0
33		Taxes Other Than Income	1.1	(58,155,759)	(216,393)	(665,660)	(1,238)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 2,393,778	$ 1,317,619	$ (31,153)
35		Interest Expense	1.1	(47,329,818)	(176,111)	(541,744)	(1,008)
36		State Taxable Income		$ 47,926,899	$ 2,217,667	$ 775,875	$ (32,160)
37		State Income Tax	4.90%	$ 2,348,418	$ 108,666	$ 38,018	$ (1,576)
38		Total State Income Tax		$ 2,348,418	$ 108,666	$ 38,018	$ (1,576)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 2,393,778	$ 1,317,619	$ (31,153)
40		Interest Expense	1.1	(47,329,818)	(176,111)	(541,744)	(1,008)
41		Federal Taxable Income		$ 47,926,899	$ 2,217,667	$ 775,875	$ (32,160)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 442,890	$ 154,950	$ (6,423)
43		South Georgia Federal	1.1	(15,458,159)	(57,519)	(176,936)	(329)
44		Total Federal Income Tax		$ (5,886,678)	$ 385,372	$ (21,986)	$ (6,752)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 1,899,741	$ 1,301,588	$ (22,825)
47		Rate of Return on Rate Base		3.78%	18.14%	4.52%	-41.78%
48		Rate of Return by Class Total				8.08%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Demand	Medium General Customer	Medium General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 1,510	$ 2,855	$ 16
2	360 - 363.50	Storage Plant	2.0	3,619,500	238,449	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	1,784,793	3,375,401	19,013
4	389 - 398	General Plant	1.1	12,828,977	269,831	510,305	2,874
5		Total Direct Depreciation Expense		$ 101,377,269	$ 2,294,582	$ 3,888,561	$ 21,903
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 213,328	$ 403,446	$ 2,272
7		General Plant	1.1	4,536,929	95,425	180,468	1,017
8		Total System Allocable Amortization		$ 14,679,481	$ 308,753	$ 583,913	$ 3,289
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 95,425	$ 180,468	$ 1,017
10		Total Depreciation Expense		$ 116,056,749	$ 2,603,335	$ 4,472,474	$ 25,192
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(214,350)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (72,128)	$ (136,408)	$ (768)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 2,531,207	$ 4,336,066	$ 24,424
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	95,887
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 95,887
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 96,848	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 95,342	$ 1,300,632	$ 12,246
22		Materials & Expenses	5.5	1,448,039	13,794	188,182	1,772
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	36,577
24		Materials & Expenses	3.0	157,480	0	0	11,118
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	107,952	96,686	0
26		Materials & Expenses	4.4	7,944,286	185,255	165,921	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	56,332	12,381	0
28		Materials & Expenses	2.2	698,517	21,781	4,787	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	1,559,149	0
30		Materials & Expenses	6.0	3,177,057	0	654,685	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	2,201,335	0
32		Materials & Expenses	6.0	1,798,117	0	370,532	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	62,323	850,204	8,005
34		Materials & Expenses	5.5	6,591,122	62,789	856,557	8,065
35	881.00	Rents	5.5	(724,435)	(6,901)	(94,145)	(886)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 598,667	$ 8,166,905	$ 76,898
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 695,514	$ 8,166,905	$ 172,784

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Demand	Medium General Customer	Medium General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 43,692	$ 89,429	$ 0
2		Materials & Expenses	6.6	264,999	5,127	10,493	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	1,610	0	0
4		Materials & Expenses	1.0	53,126	3,313	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	360,131	79,152	0
6		Materials & Expenses	2.2	12,648,532	394,398	86,683	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	57,474	12,632	0
8		Materials & Expenses	2.2	733,457	22,870	5,027	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	363,633	0
10		Materials & Expenses	3.3	7,070,213	0	441,930	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	500,675	0
12		Materials & Expenses	6.0	1,063,225	0	219,095	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	5,558	11,377	0
14		Materials & Expenses	6.6	73,309	1,418	2,903	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 895,591	$ 1,823,028	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 1,591,106	$ 9,989,933	$ 172,784
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 30,386	$ 0
18		Materials & Expenses	10.1	262,816	0	5,054	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	16,900	0
20		Materials & Expenses	11.0	324,290	0	4,445	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	96,702	0
22		Materials & Expenses	4.0	12,941,582	0	177,383	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	140,963	0
24		Materials & Expenses - KAM	15.0	2,968	0	539	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	18,514	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	2,309	0
27		Materials & Expenses	10.1	1,641	0	32	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 493,226	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	5,200	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 5,200	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	104	0
42		Total Sales Expense		$ 7,579	$ 0	$ 104	$ 0
43		Total O & M Expense		$ 137,825,696	$ 1,591,106	$ 10,488,462	$ 172,784
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Demand	Medium General Customer	Medium General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 1,082,962	$ 7,138,813	$ 117,603
2		Interest on Customer Deposits	8.0	958,434	0	13,239	0
3		Taxes Other Than Income	1.1	58,155,759	1,223,187	2,313,292	13,030
4		Total Allocated Operating Deductions		$ 290,748,856	$ 3,897,254	$ 19,953,805	$ 303,418
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 995,485	$ 1,882,663	$ 10,605
6		South Georgia - Federal	1.1	(15,458,159)	(325,131)	(614,887)	(3,463)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 69,876,216	$ 122,435,308	$ 689,643
8		Total Common Systems Allocable Net Plant		95,625,305	2,011,282	3,803,737	21,425
9		Cash Working Capital	1.1	(10,297,032)	(118,872)	(783,599)	(12,909)
10		Materials & Supplies	1.1	36,813,908	774,305	1,464,366	8,248
11		Prepayments	1.1	7,721,011	162,396	307,123	1,730
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(470,236)	0
14		Customer Advances	9.0	(41,613,406)	0	(530,836)	0
15		Deferred Taxes	1.1	(594,534,243)	(12,504,806)	(23,649,095)	(133,209)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 60,200,520	$ 102,576,767	$ 574,929
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 18,745,450	$ 7,749,917	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	193,988	80,200	0
20		Late Charges	12.0	1,615,145	0	65,382	0
21		Service Establishment Charges	9.0	7,218,698	0	92,084	0
22		Reconnect / Reread Charges	9.0	224,248	0	2,861	0
23		Other Revenue - Labor	Net Op Margin	4,325	168	69	0
24		Other Revenue - Parts & Material	Net Op Margin	377	15	6	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(1)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	5,460	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	4,411	1,823	0
28		Total Revenue		$ 498,633,048	$ 18,944,030	$ 7,997,803	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (1,591,106)	$ (10,488,462)	$ (172,784)
30		A & G	Total O&M	(93,808,967)	(1,082,962)	(7,138,813)	(117,603)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(2,531,207)	(4,336,066)	(24,424)
32		Interest on Customer Deposits	8.0	(958,434)	0	(13,239)	0
33		Taxes Other Than Income	1.1	(58,155,759)	(1,223,187)	(2,313,292)	(13,030)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 12,515,568	$ (16,292,068)	$ (327,841)
35		Interest Expense	1.1	(47,329,818)	(995,485)	(1,882,663)	(10,605)
36		State Taxable Income		$ 47,926,899	$ 11,520,083	$ (18,174,731)	$ (338,446)
37		State Income Tax	4.90%	$ 2,348,418	$ 564,484	$ (890,562)	$ (16,584)
38		Total State Income Tax		$ 2,348,418	$ 564,484	$ (890,562)	$ (16,584)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 12,515,568	$ (16,292,068)	$ (327,841)
40		Interest Expense	1.1	(47,329,818)	(995,485)	(1,882,663)	(10,605)
41		Federal Taxable Income		$ 47,926,899	$ 11,520,083	$ (18,174,731)	$ (338,446)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 2,300,676	$ (3,629,676)	$ (67,591)
43		South Georgia Federal	1.1	(15,458,159)	(325,131)	(614,887)	(3,463)
44		Total Federal Income Tax		$ (5,886,678)	$ 1,975,545	$ (4,244,563)	$ (71,055)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 9,975,539	$ (11,156,944)	$ (240,203)
47		Rate of Return on Rate Base		3.78%	16.57%	-10.88%	-41.78%
48		Rate of Return by Class Total				-0.87%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large-1 General Demand	Large-1 General Customer	Large-1 General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 3,204	$ 1,098	$ 38
2	360 - 363.50	Storage Plant	2.0	3,619,500	524,202	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	3,787,715	1,298,468	45,152
4	389 - 398	General Plant	1.1	12,828,977	572,640	196,307	6,826
5		Total Direct Depreciation Expense		$ 101,377,269	$ 4,887,760	$ 1,495,874	$ 52,017
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 452,727	$ 155,200	$ 5,397
7		General Plant	1.1	4,536,929	202,512	69,423	2,414
8		Total System Allocable Amortization		$ 14,679,481	$ 655,240	$ 224,623	$ 7,811
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 202,512	$ 69,423	$ 2,414
10		Total Depreciation Expense		$ 116,056,749	$ 5,543,000	$ 1,720,497	$ 59,827
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(30,223)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (153,071)	$ (52,474)	$ (1,825)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 5,389,929	$ 1,668,023	$ 58,003
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	227,716
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 227,716
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 212,909	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 202,335	$ 656,728	$ 29,083
22		Materials & Expenses	5.5	1,448,039	29,275	95,019	4,208
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	86,865
24		Materials & Expenses	3.0	157,480	0	0	26,404
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	229,097	21,589	0
26		Materials & Expenses	4.4	7,944,286	393,150	37,048	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	119,550	5,898	0
28		Materials & Expenses	2.2	698,517	46,223	2,280	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	811,517	0
30		Materials & Expenses	6.0	3,177,057	0	340,755	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	1,145,766	0
32		Materials & Expenses	6.0	1,798,117	0	192,857	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	132,263	429,293	19,011
34		Materials & Expenses	5.5	6,591,122	133,252	432,501	19,153
35	881.00	Rents	5.5	(724,435)	(14,646)	(47,537)	(2,105)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 1,270,499	$ 4,123,715	$ 182,620
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 1,483,408	$ 4,123,715	$ 410,336

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large-1 General Demand	Large-1 General Customer	Large-1 General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 92,724	$ 30,124	$ 0
2		Materials & Expenses	6.6	264,999	10,880	3,535	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	3,416	0	0
4		Materials & Expenses	1.0	53,126	7,031	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	764,275	37,703	0
6		Materials & Expenses	2.2	12,648,532	836,999	41,291	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	121,971	6,017	0
8		Materials & Expenses	2.2	733,457	48,535	2,394	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	51,271	0
10		Materials & Expenses	3.3	7,070,213	0	62,310	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	260,595	0
12		Materials & Expenses	6.0	1,063,225	0	114,036	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	11,796	3,832	0
14		Materials & Expenses	6.6	73,309	3,010	978	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 1,900,637	$ 614,087	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 3,384,045	$ 4,737,802	$ 410,336
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 27,133	$ 0
18		Materials & Expenses	10.1	262,816	0	4,513	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	8,050	0
20		Materials & Expenses	11.0	324,290	0	2,117	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	46,063	0
22		Materials & Expenses	4.0	12,941,582	0	84,495	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	256,158	0
24		Materials & Expenses - KAM	15.0	2,968	0	980	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	8,819	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	2,061	0
27		Materials & Expenses	10.1	1,641	0	28	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 440,418	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	2,477	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 2,477	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	49	0
42		Total Sales Expense		$ 7,579	$ 0	$ 49	$ 0
43		Total O & M Expense		$ 137,825,696	$ 3,384,045	$ 5,180,747	$ 410,336
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large-1 General Demand	Large-1 General Customer	Large-1 General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 2,303,299	$ 3,526,197	$ 279,289
2		Interest on Customer Deposits	8.0	958,434	0	0	0
3		Taxes Other Than Income	1.1	58,155,759	2,595,866	889,890	30,944
4		Total Allocated Operating Deductions		$ 290,748,856	$ 8,283,210	$ 9,596,833	$ 720,569
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 2,112,634	$ 724,233	$ 25,184
6		South Georgia - Federal	1.1	(15,458,159)	(689,997)	(236,538)	(8,225)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 148,683,640	$ 47,099,110	$ 1,637,794
8		Total Common Systems Allocable Net Plant		95,625,305	4,268,373	1,463,243	50,882
9		Cash Working Capital	1.1	(10,297,032)	(252,824)	(387,056)	(30,656)
10		Materials & Supplies	1.1	36,813,908	1,643,242	563,321	19,589
11		Prepayments	1.1	7,721,011	344,638	118,146	4,108
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(167,303)	0
14		Customer Advances	9.0	(41,613,406)	0	(188,864)	0
15		Deferred Taxes	1.1	(594,534,243)	(26,537,890)	(9,097,468)	(316,349)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 128,149,179	$ 39,403,128	$ 1,365,367
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 41,949,603	$ 6,789,200	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	434,117	70,258	0
20		Late Charges	12.0	1,615,145	0	87,311	0
21		Service Establishment Charges	9.0	7,218,698	0	32,762	0
22		Reconnect / Reread Charges	9.0	224,248	0	1,018	0
23		Other Revenue - Labor	Net Op Margin	4,325	375	61	0
24		Other Revenue - Parts & Material	Net Op Margin	377	33	5	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(2)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	2,058	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	9,870	1,597	0
28		Total Revenue		$ 498,633,048	$ 42,393,996	$ 6,984,270	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (3,384,045)	$ (5,180,747)	$ (410,336)
30		A & G	Total O&M	(93,808,967)	(2,303,299)	(3,526,197)	(279,289)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(5,389,929)	(1,668,023)	(58,003)
32		Interest on Customer Deposits	8.0	(958,434)	0	0	0
33		Taxes Other Than Income	1.1	(58,155,759)	(2,595,866)	(889,890)	(30,944)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 28,720,856	$ (4,280,586)	$ (778,572)
35		Interest Expense	1.1	(47,329,818)	(2,112,634)	(724,233)	(25,184)
36		State Taxable Income		$ 47,926,899	$ 26,608,222	$ (5,004,819)	$ (803,756)
37		State Income Tax	4.90%	$ 2,348,418	$ 1,303,803	$ (245,236)	$ (39,384)
38		Total State Income Tax		$ 2,348,418	$ 1,303,803	$ (245,236)	$ (39,384)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 28,720,856	$ (4,280,586)	$ (778,572)
40		Interest Expense	1.1	(47,329,818)	(2,112,634)	(724,233)	(25,184)
41		Federal Taxable Income		$ 47,926,899	$ 26,608,222	$ (5,004,819)	$ (803,756)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 5,313,928	$ (999,512)	$ (160,518)
43		South Georgia Federal	1.1	(15,458,159)	(689,997)	(236,538)	(8,225)
44		Total Federal Income Tax		$ (5,886,678)	$ 4,623,931	$ (1,236,051)	$ (168,743)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 22,793,122	$ (2,799,299)	$ (570,444)
47		Rate of Return on Rate Base		3.78%	17.79%	-7.10%	-41.78%
48		Rate of Return by Class Total				11.50%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large-2 General Demand	Large-2 General Customer	Large-2 General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 1,018	$ 441	$ 13
2	360 - 363.50	Storage Plant	2.0	3,619,500	172,490	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	1,203,853	521,850	15,353
4	389 - 398	General Plant	1.1	12,828,977	182,003	78,895	2,321
5		Total Direct Depreciation Expense		$ 101,377,269	$ 1,559,363	$ 601,187	$ 17,687
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 143,891	$ 62,374	$ 1,835
7		General Plant	1.1	4,536,929	64,365	27,901	821
8		Total System Allocable Amortization		$ 14,679,481	$ 208,255	$ 90,275	$ 2,656
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 64,365	$ 27,901	$ 821
10		Total Depreciation Expense		$ 116,056,749	$ 1,767,619	$ 691,462	$ 20,343
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(16,745)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (48,651)	$ (21,089)	$ (620)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 1,718,968	$ 670,373	$ 19,722
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	77,428
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 77,428
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 70,058	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 64,308	$ 287,578	$ 9,889
22		Materials & Expenses	5.5	1,448,039	9,304	41,608	1,431
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	29,536
24		Materials & Expenses	3.0	157,480	0	0	8,978
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	72,814	6,394	0
26		Materials & Expenses	4.4	7,944,286	124,955	10,973	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	37,997	362	0
28		Materials & Expenses	2.2	698,517	14,691	140	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	359,070	0
30		Materials & Expenses	6.0	3,177,057	0	150,773	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	506,964	0
32		Materials & Expenses	6.0	1,798,117	0	85,333	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	42,037	187,986	6,464
34		Materials & Expenses	5.5	6,591,122	42,352	189,390	6,513
35	881.00	Rents	5.5	(724,435)	(4,655)	(20,816)	(716)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 403,804	$ 1,805,755	$ 62,095
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 473,862	$ 1,805,755	$ 139,523

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large-2 General Demand	Large-2 General Customer	Large-2 General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 29,471	$ 12,250	$ 0
2		Materials & Expenses	6.6	264,999	3,458	1,437	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	1,086	0	0
4		Materials & Expenses	1.0	53,126	2,235	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	242,910	2,317	0
6		Materials & Expenses	2.2	12,648,532	266,024	2,538	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	38,766	370	0
8		Materials & Expenses	2.2	733,457	15,426	147	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	28,407	0
10		Materials & Expenses	3.3	7,070,213	0	34,524	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	115,305	0
12		Materials & Expenses	6.0	1,063,225	0	50,457	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	3,749	1,558	0
14		Materials & Expenses	6.6	73,309	957	398	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 604,081	$ 249,708	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 1,077,943	$ 2,055,464	$ 139,523
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 8,430	$ 0
18		Materials & Expenses	10.1	262,816	0	1,402	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	495	0
20		Materials & Expenses	11.0	324,290	0	130	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	2,831	0
22		Materials & Expenses	4.0	12,941,582	0	5,193	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	116,711	0
24		Materials & Expenses - KAM	15.0	2,968	0	446	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	542	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	640	0
27		Materials & Expenses	10.1	1,641	0	9	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 136,830	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	152	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 152	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	3	0
42		Total Sales Expense		$ 7,579	$ 0	$ 3	$ 0
43		Total O & M Expense		$ 137,825,696	$ 1,077,943	$ 2,192,449	$ 139,523
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No. (a)	Description (b)	Allocation Factor No. (c)	Total Amount (d)	Large-2 General Demand (e)	Large-2 General Customer (f)	Large-2 General Commodity (g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 733,686	$ 1,492,257	$ 94,964
2		Interest on Customer Deposits	8.0	958,434	0	0	0
3		Taxes Other Than Income	1.1	58,155,759	825,046	357,644	10,522
4		Total Allocated Operating Deductions		$ 290,748,856	$ 2,636,675	$ 4,042,350	$ 245,009
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 671,461	$ 291,067	$ 8,563
6		South Georgia - Federal	1.1	(15,458,159)	(219,302)	(95,064)	(2,797)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 47,382,969	$ 18,928,971	$ 556,886
8		Total Common Systems Allocable Net Plant		95,625,305	1,356,621	588,072	17,301
9		Cash Working Capital	1.1	(10,297,032)	(80,534)	(163,799)	(10,424)
10		Materials & Supplies	1.1	36,813,908	522,273	226,397	6,661
11		Prepayments	1.1	7,721,011	109,537	47,482	1,397
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(10,995)	0
14		Customer Advances	9.0	(41,613,406)	0	(12,412)	0
15		Deferred Taxes	1.1	(594,534,243)	(8,434,562)	(3,656,241)	(107,566)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 40,856,304	$ 15,947,475	$ 464,255
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 10,551,202	$ 2,451,520	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	109,189	25,370	0
20		Late Charges	12.0	1,615,145	0	27,490	0
21		Service Establishment Charges	9.0	7,218,698	0	2,153	0
22		Reconnect / Reread Charges	9.0	224,248	0	67	0
23		Other Revenue - Labor	Net Op Margin	4,325	94	22	0
24		Other Revenue - Parts & Material	Net Op Margin	377	8	2	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(0)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	140	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	2,483	577	0
28		Total Revenue		$ 498,633,048	$ 10,662,976	$ 2,507,340	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (1,077,943)	$ (2,192,449)	$ (139,523)
30		A & G	Total O&M	(93,808,967)	(733,686)	(1,492,257)	(94,964)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(1,718,968)	(670,373)	(19,722)
32		Interest on Customer Deposits	8.0	(958,434)	0	0	0
33		Taxes Other Than Income	1.1	(58,155,759)	(825,046)	(357,644)	(10,522)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 6,307,333	$ (2,205,382)	$ (264,731)
35		Interest Expense	1.1	(47,329,818)	(671,461)	(291,067)	(8,563)
36		State Taxable Income		$ 47,926,899	$ 5,635,872	$ (2,496,449)	$ (273,295)
37		State Income Tax	4.90%	$ 2,348,418	$ 276,158	$ (122,326)	$ (13,391)
38		Total State Income Tax		$ 2,348,418	$ 276,158	$ (122,326)	$ (13,391)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 6,307,333	$ (2,205,382)	$ (264,731)
40		Interest Expense	1.1	(47,329,818)	(671,461)	(291,067)	(8,563)
41		Federal Taxable Income		$ 47,926,899	$ 5,635,872	$ (2,496,449)	$ (273,295)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 1,125,540	$ (498,566)	$ (54,580)
43		South Georgia Federal	1.1	(15,458,159)	(219,302)	(95,064)	(2,797)
44		Total Federal Income Tax		$ (5,886,678)	$ 906,238	$ (593,630)	$ (57,376)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 5,124,937	$ (1,489,426)	$ (193,964)
47		Rate of Return on Rate Base		3.78%	12.54%	-9.34%	-41.78%
48		Rate of Return by Class Total				6.01%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible General Demand	Transportation Eligible General Customer	Transportation Eligible General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 2,866	$ 175	$ 42
2	360 - 363.50	Storage Plant	2.0	3,619,500	538,431	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	3,388,048	206,906	49,856
4	389 - 398	General Plant	1.1	12,828,977	512,217	31,281	7,537
5		Total Direct Depreciation Expense		$ 101,377,269	$ 4,441,562	$ 238,362	$ 57,436
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 404,957	$ 24,731	$ 5,959
7		General Plant	1.1	4,536,929	181,144	11,062	2,666
8		Total System Allocable Amortization		$ 14,679,481	$ 586,101	$ 35,793	$ 8,625
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 181,144	$ 11,062	$ 2,666
10		Total Depreciation Expense		$ 116,056,749	$ 5,027,663	$ 274,155	$ 66,061
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(4,307)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (136,919)	$ (8,362)	$ (2,015)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 4,890,744	$ 265,794	$ 64,046
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	251,440
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 251,440
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 218,688	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 180,985	$ 121,512	$ 32,114
22		Materials & Expenses	5.5	1,448,039	26,186	17,581	4,646
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	95,915
24		Materials & Expenses	3.0	157,480	0	0	29,155
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	204,923	1,789	0
26		Materials & Expenses	4.4	7,944,286	351,666	3,070	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	106,935	168	0
28		Materials & Expenses	2.2	698,517	41,346	65	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	152,521	0
30		Materials & Expenses	6.0	3,177,057	0	64,043	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	215,342	0
32		Materials & Expenses	6.0	1,798,117	0	36,247	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	118,307	79,431	20,992
34		Materials & Expenses	5.5	6,591,122	119,192	80,024	21,149
35	881.00	Rents	5.5	(724,435)	(13,100)	(8,796)	(2,325)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 1,136,441	$ 762,998	$ 201,647
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 1,355,129	$ 762,998	$ 453,087

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible General Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 82,940	$ 4,663	$ 0
2		Materials & Expenses	6.6	264,999	9,732	547	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	3,056	0	0
4		Materials & Expenses	1.0	53,126	6,289	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	683,632	1,077	0
6		Materials & Expenses	2.2	12,648,532	748,681	1,179	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	109,101	172	0
8		Materials & Expenses	2.2	733,457	43,414	68	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	7,307	0
10		Materials & Expenses	3.3	7,070,213	0	8,880	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	48,978	0
12		Materials & Expenses	6.0	1,063,225	0	21,433	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	10,552	593	0
14		Materials & Expenses	6.6	73,309	2,692	151	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 1,700,089	$ 95,048	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 3,055,217	$ 858,045	$ 453,087
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 14,497	$ 0
18		Materials & Expenses	10.1	262,816	0	2,411	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	230	0
20		Materials & Expenses	11.0	324,290	0	60	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	1,316	0
22		Materials & Expenses	4.0	12,941,582	0	2,413	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	212,202	0
24		Materials & Expenses - KAM	15.0	2,968	0	812	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	252	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	1,101	0
27		Materials & Expenses	10.1	1,641	0	15	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 235,309	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	71	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 71	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	1	0
42		Total Sales Expense		$ 7,579	$ 0	$ 1	$ 0
43		Total O & M Expense		$ 137,825,696	$ 3,055,217	$ 1,093,427	$ 453,087
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible General Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 2,079,487	$ 744,224	$ 308,387
2		Interest on Customer Deposits	8.0	958,434	0	0	0
3		Taxes Other Than Income	1.1	58,155,759	2,321,959	141,801	34,168
4		Total Allocated Operating Deductions		$ 290,748,856	$ 7,456,663	$ 1,979,452	$ 795,642
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 1,889,716	$ 115,404	$ 27,808
6		South Georgia - Federal	1.1	(15,458,159)	(617,191)	(37,692)	(9,082)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 134,493,139	$ 7,505,081	$ 1,808,430
8		Total Common Systems Allocable Net Plant		95,625,305	3,817,989	233,163	56,183
9		Cash Working Capital	1.1	(10,297,032)	(228,257)	(81,690)	(33,850)
10		Materials & Supplies	1.1	36,813,908	1,469,852	89,763	21,629
11		Prepayments	1.1	7,721,011	308,273	18,826	4,536
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	0	0
14		Customer Advances	9.0	(41,613,406)	0	0	0
15		Deferred Taxes	1.1	(594,534,243)	(23,737,702)	(1,449,650)	(349,309)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 116,123,294	$ 6,315,493	$ 1,507,619
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 29,543,216	$ 2,302,800	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	305,729	23,831	0
20		Late Charges	12.0	1,615,145	0	26,176	0
21		Service Establishment Charges	9.0	7,218,698	0	0	0
22		Reconnect / Reread Charges	9.0	224,248	0	0	0
23		Other Revenue - Labor	Net Op Margin	4,325	264	21	0
24		Other Revenue - Parts & Material	Net Op Margin	377	23	2	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(1)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	14	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	6,951	542	0
28		Total Revenue		$ 498,633,048	$ 29,856,182	$ 2,353,385	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (3,055,217)	$ (1,093,427)	$ (453,087)
30		A & G	Total O&M	(93,808,967)	(2,079,487)	(744,224)	(308,387)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(4,890,744)	(265,794)	(64,046)
32		Interest on Customer Deposits	8.0	(958,434)	0	0	0
33		Taxes Other Than Income	1.1	(58,155,759)	(2,321,959)	(141,801)	(34,168)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 17,508,774	$ 108,140	$ (859,688)
35		Interest Expense	1.1	(47,329,818)	(1,889,716)	(115,404)	(27,808)
36		State Taxable Income		$ 47,926,899	$ 15,619,058	$ (7,265)	$ (887,496)
37		State Income Tax	4.90%	$ 2,348,418	$ 765,334	$ (356)	$ (43,487)
38		Total State Income Tax		$ 2,348,418	$ 765,334	$ (356)	$ (43,487)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 17,508,774	$ 108,140	$ (859,688)
40		Interest Expense	1.1	(47,329,818)	(1,889,716)	(115,404)	(27,808)
41		Federal Taxable Income		$ 47,926,899	$ 15,619,058	$ (7,265)	$ (887,496)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 3,119,282	$ (1,451)	$ (177,242)
43		South Georgia Federal	1.1	(15,458,159)	(617,191)	(37,692)	(9,082)
44		Total Federal Income Tax		$ (5,886,678)	$ 2,502,091	$ (39,142)	$ (186,324)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 14,241,349	$ 147,638	$ (629,877)
47		Rate of Return on Rate Base		3.78%	12.26%	2.34%	-41.78%
48		Rate of Return by Class Total				11.10%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air Conditioning Demand	Air Conditioning Customer	Air Conditioning Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 3	$ 1	$ 0
2	360 - 363.50	Storage Plant	2.0	3,619,500	1,012	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	3,786	809	94
4	389 - 398	General Plant	1.1	12,828,977	572	122	14
5		Total Direct Depreciation Expense		$ 101,377,269	$ 5,374	$ 932	$ 109
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 453	$ 97	$ 11
7		General Plant	1.1	4,536,929	202	43	5
8		Total System Allocable Amortization		$ 14,679,481	$ 655	$ 140	$ 16
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 202	$ 43	$ 5
10		Total Depreciation Expense		$ 116,056,749	$ 6,029	$ 1,072	$ 125
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(39)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (153)	$ (33)	$ (4)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 5,876	$ 1,039	$ 121
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	476
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 476
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 411	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 202	$ 101	$ 61
22		Materials & Expenses	5.5	1,448,039	29	15	9
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	182
24		Materials & Expenses	3.0	157,480	0	0	55
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	229	44	0
26		Materials & Expenses	4.4	7,944,286	393	75	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	120	16	0
28		Materials & Expenses	2.2	698,517	46	6	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	83	0
30		Materials & Expenses	6.0	3,177,057	0	35	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	117	0
32		Materials & Expenses	6.0	1,798,117	0	20	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	132	66	40
34		Materials & Expenses	5.5	6,591,122	133	67	40
35	881.00	Rents	5.5	(724,435)	(15)	(7)	(4)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 1,270	$ 636	$ 382
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 1,681	$ 636	$ 858

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air Conditioning Demand	Air Conditioning Customer	Air Conditioning Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 93	$ 22	$ 0
2		Materials & Expenses	6.6	264,999	11	3	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	3	0	0
4		Materials & Expenses	1.0	53,126	7	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	764	101	0
6		Materials & Expenses	2.2	12,648,532	837	111	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	122	16	0
8		Materials & Expenses	2.2	733,457	49	6	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	66	0
10		Materials & Expenses	3.3	7,070,213	0	81	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	27	0
12		Materials & Expenses	6.0	1,063,225	0	12	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	12	3	0
14		Materials & Expenses	6.6	73,309	3	1	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 1,900	$ 448	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 3,581	$ 1,084	$ 858
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 128	$ 0
18		Materials & Expenses	10.1	262,816	0	21	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	22	0
20		Materials & Expenses	11.0	324,290	0	6	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	124	0
22		Materials & Expenses	4.0	12,941,582	0	227	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	1,516	0
24		Materials & Expenses - KAM	15.0	2,968	0	6	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	24	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	10	0
27		Materials & Expenses	10.1	1,641	0	0	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 2,083	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	7	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 7	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	0	0
42		Total Sales Expense		$ 7,579	$ 0	$ 0	$ 0
43		Total O & M Expense		$ 137,825,696	$ 3,581	$ 3,174	$ 858
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air Conditioning Demand	Air Conditioning Customer	Air Conditioning Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 2,437	$ 2,160	$ 584
2		Interest on Customer Deposits	8.0	958,434	0	0	0
3		Taxes Other Than Income	1.1	58,155,759	2,595	555	65
4		Total Allocated Operating Deductions		$ 290,748,856	$ 8,613	$ 5,888	$ 1,506
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 2,112	$ 451	$ 53
6		South Georgia - Federal	1.1	(15,458,159)	(690)	(147)	(17)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 159,141	$ 29,351	$ 3,424
8		Total Common Systems Allocable Net Plant		95,625,305	4,267	912	106
9		Cash Working Capital	1.1	(10,297,032)	(268)	(237)	(64)
10		Materials & Supplies	1.1	36,813,908	1,643	351	41
11		Prepayments	1.1	7,721,011	345	74	9
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	0	0
14		Customer Advances	9.0	(41,613,406)	0	0	0
15		Deferred Taxes	1.1	(594,534,243)	(26,529)	(5,669)	(661)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 138,599	$ 24,781	$ 2,854
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 31,843	$ 9,870	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	330	102	0
20		Late Charges	12.0	1,615,145	0	559	0
21		Service Establishment Charges	9.0	7,218,698	0	0	0
22		Reconnect / Reread Charges	9.0	224,248	0	0	0
23		Other Revenue - Labor	Net Op Margin	4,325	0	0	0
24		Other Revenue - Parts & Material	Net Op Margin	377	0	0	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(0)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	0	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	7	2	0
28		Total Revenue		$ 498,633,048	$ 32,180	$ 10,534	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (3,581)	$ (3,174)	$ (858)
30		A & G	Total O&M	(93,808,967)	(2,437)	(2,160)	(584)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(5,876)	(1,039)	(121)
32		Interest on Customer Deposits	8.0	(958,434)	0	0	0
33		Taxes Other Than Income	1.1	(58,155,759)	(2,595)	(555)	(65)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 17,691	$ 3,606	$ (1,627)
35		Interest Expense	1.1	(47,329,818)	(2,112)	(451)	(53)
36		State Taxable Income		$ 47,926,899	$ 15,579	$ 3,155	$ (1,680)
37		State Income Tax	4.90%	$ 2,348,418	$ 763	$ 155	$ (82)
38		Total State Income Tax		$ 2,348,418	$ 763	$ 155	$ (82)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 17,691	$ 3,606	$ (1,627)
40		Interest Expense	1.1	(47,329,818)	(2,112)	(451)	(53)
41		Federal Taxable Income		$ 47,926,899	$ 15,579	$ 3,155	$ (1,680)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 3,111	$ 630	$ (336)
43		South Georgia Federal	1.1	(15,458,159)	(690)	(147)	(17)
44		Total Federal Income Tax		$ (5,886,678)	$ 2,422	$ 483	$ (353)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 14,506	$ 2,969	$ (1,192)
47		Rate of Return on Rate Base		3.78%	10.47%	11.98%	-41.78%
48		Rate of Return by Class Total				9.80%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Demand	Street Lighting Customer	Street Lighting Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 0	$ 2	$ 0
2	360 - 363.50	Storage Plant	2.0	3,619,500	48	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	258	2,263	5
4	389 - 398	General Plant	1.1	12,828,977	39	342	1
5		Total Direct Depreciation Expense		$ 101,377,269	$ 345	$ 2,607	$ 5
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 31	$ 270	$ 1
7		General Plant	1.1	4,536,929	14	121	0
8		Total System Allocable Amortization		$ 14,679,481	$ 45	$ 391	$ 1
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 14	$ 121	$ 0
10		Total Depreciation Expense		$ 116,056,749	$ 390	$ 2,998	$ 6
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(126)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (10)	$ (91)	$ (0)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 379	$ 2,907	$ 6
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	23
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 23
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 20	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 14	$ 115	$ 3
22		Materials & Expenses	5.5	1,448,039	2	17	0
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	9
24		Materials & Expenses	3.0	157,480	0	0	3
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	16	139	0
26		Materials & Expenses	4.4	7,944,286	27	238	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	8	50	0
28		Materials & Expenses	2.2	698,517	3	19	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	0	0
30		Materials & Expenses	6.0	3,177,057	0	0	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	0	0
32		Materials & Expenses	6.0	1,798,117	0	0	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	9	75	2
34		Materials & Expenses	5.5	6,591,122	9	75	2
35	881.00	Rents	5.5	(724,435)	(1)	(8)	(0)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 87	$ 719	$ 19
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 106	$ 719	$ 42

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Demand	Street Lighting Customer	Street Lighting Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 6	$ 64	$ 0
2		Materials & Expenses	6.6	264,999	1	7	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	0	0	0
4		Materials & Expenses	1.0	53,126	0	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	52	320	0
6		Materials & Expenses	2.2	12,648,532	57	350	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	8	51	0
8		Materials & Expenses	2.2	733,457	3	20	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	213	0
10		Materials & Expenses	3.3	7,070,213	0	259	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	0	0
12		Materials & Expenses	6.0	1,063,225	0	0	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	1	8	0
14		Materials & Expenses	6.6	73,309	0	2	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 129	$ 1,296	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 235	$ 2,015	$ 42
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 85	$ 0
18		Materials & Expenses	10.1	262,816	0	14	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	68	0
20		Materials & Expenses	11.0	324,290	0	18	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	391	0
22		Materials & Expenses	4.0	12,941,582	0	717	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	0	0
24		Materials & Expenses - KAM	15.0	2,968	0	0	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	75	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	6	0
27		Materials & Expenses	10.1	1,641	0	0	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 1,374	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	21	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 21	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	0	0
42		Total Sales Expense		$ 7,579	$ 0	$ 0	$ 0
43		Total O & M Expense		$ 137,825,696	$ 235	$ 3,410	$ 42
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No. (a)	Description (b)	Allocation Factor No. (c)	Total Amount (d)	Street Lighting Demand (e)	Street Lighting Customer (f)	Street Lighting Commodity (g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 160	$ 2,321	$ 28
2		Interest on Customer Deposits	8.0	958,434	0	0	0
3		Taxes Other Than Income	1.1	58,155,759	177	1,551	3
4		Total Allocated Operating Deductions		$ 290,748,856	$ 572	$ 7,282	$ 73
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 144	$ 1,262	$ 3
6		South Georgia - Federal	1.1	(15,458,159)	(47)	(412)	(1)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 10,391	$ 82,070	$ 166
8		Total Common Systems Allocable Net Plant		95,625,305	291	2,550	5
9		Cash Working Capital	1.1	(10,297,032)	(18)	(255)	(3)
10		Materials & Supplies	1.1	36,813,908	112	982	2
11		Prepayments	1.1	7,721,011	23	206	0
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(594)	0
14		Customer Advances	9.0	(41,613,406)	0	(671)	0
15		Deferred Taxes	1.1	(594,534,243)	(1,807)	(15,852)	(32)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 8,993	$ 68,435	$ 139
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 8,165	$ 0	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	84	0	0
20		Late Charges	12.0	1,615,145	0	264	0
21		Service Establishment Charges	9.0	7,218,698	0	116	0
22		Reconnect / Reread Charges	9.0	224,248	0	4	0
23		Other Revenue - Labor	Net Op Margin	4,325	0	0	0
24		Other Revenue - Parts & Material	Net Op Margin	377	0	0	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(0)	0	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	0	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	2	0	0
28		Total Revenue		$ 498,633,048	$ 8,251	$ 384	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (235)	$ (3,410)	$ (42)
30		A & G	Total O&M	(93,808,967)	(160)	(2,321)	(28)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(379)	(2,907)	(6)
32		Interest on Customer Deposits	8.0	(958,434)	0	0	0
33		Taxes Other Than Income	1.1	(58,155,759)	(177)	(1,551)	(3)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 7,300	$ (9,804)	$ (79)
35		Interest Expense	1.1	(47,329,818)	(144)	(1,262)	(3)
36		State Taxable Income		$ 47,926,899	$ 7,156	$ (11,066)	$ (82)
37		State Income Tax	4.90%	$ 2,348,418	$ 351	$ (542)	$ (4)
38		Total State Income Tax		$ 2,348,418	$ 351	$ (542)	$ (4)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 7,300	$ (9,804)	$ (79)
40		Interest Expense	1.1	(47,329,818)	(144)	(1,262)	(3)
41		Federal Taxable Income		$ 47,926,899	$ 7,156	$ (11,066)	$ (82)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 1,429	$ (2,210)	$ (16)
43		South Georgia Federal	1.1	(15,458,159)	(47)	(412)	(1)
44		Total Federal Income Tax		$ (5,886,678)	$ 1,382	$ (2,622)	$ (17)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 5,567	$ (6,640)	$ (58)
47		Rate of Return on Rate Base		3.78%	61.90%	-9.70%	-41.78%
48		Rate of Return by Class Total				-1.46%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Compression on Customer's Premises Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 192	$ 63	$ 4
2	360 - 363.50	Storage Plant	2.0	3,619,500	44,092	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	226,840	74,468	4,187
4	389 - 398	General Plant	1.1	12,828,977	34,294	11,258	633
5		Total Direct Depreciation Expense		$ 101,377,269	$ 305,419	$ 85,790	$ 4,824
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 27,113	$ 8,901	$ 500
7		General Plant	1.1	4,536,929	12,128	3,981	224
8		Total System Allocable Amortization		$ 14,679,481	$ 39,241	$ 12,882	$ 724
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 12,128	$ 3,981	$ 224
10		Total Depreciation Expense		$ 116,056,749	$ 344,660	$ 98,672	$ 5,548
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(6,875)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (9,167)	$ (3,009)	$ (169)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 335,493	$ 95,663	$ 5,379
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	21,117
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 21,117
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 17,908	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 12,118	$ 25,453	$ 2,697
22		Materials & Expenses	5.5	1,448,039	1,753	3,683	390
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	8,055
24		Materials & Expenses	3.0	157,480	0	0	2,449
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	13,720	2,463	0
26		Materials & Expenses	4.4	7,944,286	23,545	4,227	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	7,160	64	0
28		Materials & Expenses	2.2	698,517	2,768	25	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	30,088	0
30		Materials & Expenses	6.0	3,177,057	0	12,634	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	42,481	0
32		Materials & Expenses	6.0	1,798,117	0	7,150	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	7,921	16,639	1,763
34		Materials & Expenses	5.5	6,591,122	7,980	16,763	1,776
35	881.00	Rents	5.5	(724,435)	(877)	(1,842)	(195)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 76,088	$ 159,827	$ 16,935
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 93,996	$ 159,827	$ 38,052

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Compression on Customer's Premises Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 5,553	$ 2,129	$ 0
2		Materials & Expenses	6.6	264,999	652	250	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	205	0	0
4		Materials & Expenses	1.0	53,126	421	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	45,771	411	0
6		Materials & Expenses	2.2	12,648,532	50,127	450	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	7,305	66	0
8		Materials & Expenses	2.2	733,457	2,907	26	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	11,662	0
10		Materials & Expenses	3.3	7,070,213	0	14,174	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	9,662	0
12		Materials & Expenses	6.0	1,063,225	0	4,228	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	706	271	0
14		Materials & Expenses	6.6	73,309	180	69	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 113,826	$ 43,396	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 207,823	$ 203,223	$ 38,052
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 1,225	$ 0
18		Materials & Expenses	10.1	262,816	0	204	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	88	0
20		Materials & Expenses	11.0	324,290	0	23	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	502	0
22		Materials & Expenses	4.0	12,941,582	0	920	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	16,673	0
24		Materials & Expenses - KAM	15.0	2,968	0	64	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	96	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	93	0
27		Materials & Expenses	10.1	1,641	0	1	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 19,888	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	27	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 27	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	1	0
42		Total Sales Expense		$ 7,579	$ 0	$ 1	$ 0
43		Total O & M Expense		$ 137,825,696	$ 207,823	$ 223,139	$ 38,052
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Compression on Customer's Premises Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 141,451	$ 151,876	$ 25,900
2		Interest on Customer Deposits	8.0	958,434	0	0	0
3		Taxes Other Than Income	1.1	58,155,759	155,462	51,036	2,870
4		Total Allocated Operating Deductions		$ 290,748,856	$ 504,736	$ 426,051	$ 66,822
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 126,522	$ 41,535	$ 2,335
6		South Georgia - Federal	1.1	(15,458,159)	(41,323)	(13,566)	(763)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 9,177,980	$ 2,701,176	$ 151,880
8		Total Common Systems Allocable Net Plant		95,625,305	255,626	83,918	4,719
9		Cash Working Capital	1.1	(10,297,032)	(15,527)	(16,671)	(2,843)
10		Materials & Supplies	1.1	36,813,908	98,411	32,307	1,817
11		Prepayments	1.1	7,721,011	20,640	6,776	381
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(1,189)	0
14		Customer Advances	9.0	(41,613,406)	0	(1,342)	0
15		Deferred Taxes	1.1	(594,534,243)	(1,589,312)	(521,748)	(29,337)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 7,947,818	$ 2,283,228	$ 126,617
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 2,223,669	$ 86,564	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	23,012	896	0
20		Late Charges	12.0	1,615,145	0	1,920	0
21		Service Establishment Charges	9.0	7,218,698	0	233	0
22		Reconnect / Reread Charges	9.0	224,248	0	7	0
23		Other Revenue - Labor	Net Op Margin	4,325	20	1	0
24		Other Revenue - Parts & Material	Net Op Margin	377	2	0	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(0)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	0	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	523	20	0
28		Total Revenue		$ 498,633,048	$ 2,247,225	$ 89,641	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (207,823)	$ (223,139)	$ (38,052)
30		A & G	Total O&M	(93,808,967)	(141,451)	(151,876)	(25,900)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(335,493)	(95,663)	(5,379)
32		Interest on Customer Deposits	8.0	(958,434)	0	0	0
33		Taxes Other Than Income	1.1	(58,155,759)	(155,462)	(51,036)	(2,870)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 1,406,997	$ (432,073)	$ (72,200)
35		Interest Expense	1.1	(47,329,818)	(126,522)	(41,535)	(2,335)
36		State Taxable Income		$ 47,926,899	$ 1,280,474	$ (473,608)	$ (74,536)
37		State Income Tax	4.90%	$ 2,348,418	$ 62,743	$ (23,207)	$ (3,652)
38		Total State Income Tax		$ 2,348,418	$ 62,743	$ (23,207)	$ (3,652)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 1,406,997	$ (432,073)	$ (72,200)
40		Interest Expense	1.1	(47,329,818)	(126,522)	(41,535)	(2,335)
41		Federal Taxable Income		$ 47,926,899	$ 1,280,474	$ (473,608)	$ (74,536)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 255,723	$ (94,584)	$ (14,886)
43		South Georgia Federal	1.1	(15,458,159)	(41,323)	(13,566)	(763)
44		Total Federal Income Tax		$ (5,886,678)	$ 214,401	$ (108,150)	$ (15,648)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 1,129,853	$ (300,716)	$ (52,900)
47		Rate of Return on Rate Base		3.78%	14.22%	-13.17%	-41.78%
48		Rate of Return by Class Total				7.49%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Demand	Electric Generation Customer	Electric Generation Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 255	$ 9	$ 5
2	360 - 363.50	Storage Plant	2.0	3,619,500	53,730	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	301,325	10,633	5,950
4	389 - 398	General Plant	1.1	12,828,977	45,555	1,608	900
5		Total Direct Depreciation Expense		$ 101,377,269	$ 400,865	$ 12,249	$ 6,855
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 36,016	$ 1,271	$ 711
7		General Plant	1.1	4,536,929	16,110	568	318
8		Total System Allocable Amortization		$ 14,679,481	$ 52,126	$ 1,839	$ 1,029
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 16,110	$ 568	$ 318
10		Total Depreciation Expense		$ 116,056,749	$ 452,991	$ 14,089	$ 7,884
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(75)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (12,177)	$ (430)	$ (240)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 440,814	$ 13,659	$ 7,643
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	30,008
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 30,008
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 21,823	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 16,096	$ 6,505	$ 3,833
22		Materials & Expenses	5.5	1,448,039	2,329	941	555
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	11,447
24		Materials & Expenses	3.0	157,480	0	0	3,479
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	18,225	66	0
26		Materials & Expenses	4.4	7,944,286	31,276	112	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	9,511	21	0
28		Materials & Expenses	2.2	698,517	3,677	8	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	8,187	0
30		Materials & Expenses	6.0	3,177,057	0	3,438	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	11,559	0
32		Materials & Expenses	6.0	1,798,117	0	1,946	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	10,522	4,252	2,505
34		Materials & Expenses	5.5	6,591,122	10,601	4,284	2,524
35	881.00	Rents	5.5	(724,435)	(1,165)	(471)	(277)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 101,072	$ 40,847	$ 24,065
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 122,895	$ 40,847	$ 54,073

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Demand	Electric Generation Customer	Electric Generation Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 7,376	$ 229	$ 0
2		Materials & Expenses	6.6	264,999	866	27	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	272	0	0
4		Materials & Expenses	1.0	53,126	559	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	60,800	133	0
6		Materials & Expenses	2.2	12,648,532	66,586	146	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	9,703	21	0
8		Materials & Expenses	2.2	733,457	3,861	8	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	128	0
10		Materials & Expenses	3.3	7,070,213	0	155	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	2,629	0
12		Materials & Expenses	6.0	1,063,225	0	1,150	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	938	29	0
14		Materials & Expenses	6.6	73,309	239	7	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 151,202	$ 4,663	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 274,097	$ 45,510	$ 54,073
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 746	$ 0
18		Materials & Expenses	10.1	262,816	0	124	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	28	0
20		Materials & Expenses	11.0	324,290	0	7	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	163	0
22		Materials & Expenses	4.0	12,941,582	0	299	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	10,610	0
24		Materials & Expenses - KAM	15.0	2,968	0	41	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	31	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	57	0
27		Materials & Expenses	10.1	1,641	0	1	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 12,107	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	9	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 9	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	0	0
42		Total Sales Expense		$ 7,579	$ 0	$ 0	$ 0
43		Total O & M Expense		$ 137,825,696	$ 274,097	$ 57,626	$ 54,073
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Demand	Electric Generation Customer	Electric Generation Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 186,560	$ 39,222	$ 36,804
2		Interest on Customer Deposits	8.0	958,434	0	0	0
3		Taxes Other Than Income	1.1	58,155,759	206,509	7,287	4,078
4		Total Allocated Operating Deductions		$ 290,748,856	$ 667,166	$ 104,135	$ 94,955
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 168,067	$ 5,931	$ 3,319
6		South Georgia - Federal	1.1	(15,458,159)	(54,891)	(1,937)	(1,084)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 12,087,358	$ 385,682	$ 215,824
8		Total Common Systems Allocable Net Plant		95,625,305	339,562	11,982	6,705
9		Cash Working Capital	1.1	(10,297,032)	(20,478)	(4,305)	(4,040)
10		Materials & Supplies	1.1	36,813,908	130,725	4,613	2,581
11		Prepayments	1.1	7,721,011	27,417	967	541
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(297)	0
14		Customer Advances	9.0	(41,613,406)	0	(335)	0
15		Deferred Taxes	1.1	(594,534,243)	(2,111,172)	(74,497)	(41,688)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 10,453,413	$ 323,810	$ 179,925
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 2,293,806	$ 101,208	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	23,738	1,047	0
20		Late Charges	12.0	1,615,145	0	856	0
21		Service Establishment Charges	9.0	7,218,698	0	58	0
22		Reconnect / Reread Charges	9.0	224,248	0	2	0
23		Other Revenue - Labor	Net Op Margin	4,325	20	1	0
24		Other Revenue - Parts & Material	Net Op Margin	377	2	0	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(0)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	14	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	540	24	0
28		Total Revenue		$ 498,633,048	$ 2,318,105	$ 103,210	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (274,097)	$ (57,626)	$ (54,073)
30		A & G	Total O&M	(93,808,967)	(186,560)	(39,222)	(36,804)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(440,814)	(13,659)	(7,643)
32		Interest on Customer Deposits	8.0	(958,434)	0	0	0
33		Taxes Other Than Income	1.1	(58,155,759)	(206,509)	(7,287)	(4,078)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 1,210,126	$ (14,583)	$ (102,598)
35		Interest Expense	1.1	(47,329,818)	(168,067)	(5,931)	(3,319)
36		State Taxable Income		$ 47,926,899	$ 1,042,060	$ (20,514)	$ (105,917)
37		State Income Tax	4.90%	$ 2,348,418	$ 51,061	$ (1,005)	$ (5,190)
38		Total State Income Tax		$ 2,348,418	$ 51,061	$ (1,005)	$ (5,190)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 1,210,126	$ (14,583)	$ (102,598)
40		Interest Expense	1.1	(47,329,818)	(168,067)	(5,931)	(3,319)
41		Federal Taxable Income		$ 47,926,899	$ 1,042,060	$ (20,514)	$ (105,917)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 208,110	$ (4,097)	$ (21,153)
43		South Georgia Federal	1.1	(15,458,159)	(54,891)	(1,937)	(1,084)
44		Total Federal Income Tax		$ (5,886,678)	$ 153,218	$ (6,034)	$ (22,237)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 1,005,847	$ (7,544)	$ (75,172)
47		Rate of Return on Rate Base		3.78%	9.62%	-2.33%	-41.78%
48		Rate of Return by Class Total				8.42%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agricultural User Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 94	$ 7	$ 1
2	360 - 363.50	Storage Plant	2.0	3,619,500	20,111	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	111,318	8,130	1,770
4	389 - 398	General Plant	1.1	12,828,977	16,829	1,229	268
5		Total Direct Depreciation Expense		$ 101,377,269	$ 148,352	$ 9,366	$ 2,039
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 13,305	$ 972	$ 212
7		General Plant	1.1	4,536,929	5,952	435	95
8		Total System Allocable Amortization		$ 14,679,481	$ 19,257	$ 1,406	$ 306
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 5,952	$ 435	$ 95
10		Total Depreciation Expense		$ 116,056,749	$ 167,609	$ 10,772	$ 2,346
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(149)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (4,499)	$ (329)	$ (72)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 163,111	$ 10,444	$ 2,274
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	8,928
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 8,928
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 8,168	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 5,946	$ 3,782	$ 1,140
22		Materials & Expenses	5.5	1,448,039	860	547	165
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	3,406
24		Materials & Expenses	3.0	157,480	0	0	1,035
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	6,733	167	0
26		Materials & Expenses	4.4	7,944,286	11,554	287	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	3,513	61	0
28		Materials & Expenses	2.2	698,517	1,358	23	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	4,624	0
30		Materials & Expenses	6.0	3,177,057	0	1,941	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	6,528	0
32		Materials & Expenses	6.0	1,798,117	0	1,099	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	3,887	2,472	745
34		Materials & Expenses	5.5	6,591,122	3,916	2,491	751
35	881.00	Rents	5.5	(724,435)	(430)	(274)	(83)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 37,339	$ 23,749	$ 7,160
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 45,507	$ 23,749	$ 16,088

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agricultural User Demand	Small Essential Agricultural User Customer	Small Essential Agricultural User Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 2,725	$ 188	$ 0
2		Materials & Expenses	6.6	264,999	320	22	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	100	0	0
4		Materials & Expenses	1.0	53,126	207	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	22,461	388	0
6		Materials & Expenses	2.2	12,648,532	24,599	425	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	3,585	62	0
8		Materials & Expenses	2.2	733,457	1,426	25	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	253	0
10		Materials & Expenses	3.3	7,070,213	0	307	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	1,485	0
12		Materials & Expenses	6.0	1,063,225	0	650	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	347	24	0
14		Materials & Expenses	6.6	73,309	88	6	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 55,858	$ 3,835	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 101,365	$ 27,585	$ 16,088
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 813	$ 0
18		Materials & Expenses	10.1	262,816	0	135	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	83	0
20		Materials & Expenses	11.0	324,290	0	22	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	474	0
22		Materials & Expenses	4.0	12,941,582	0	870	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	10,610	0
24		Materials & Expenses - KAM	15.0	2,968	0	41	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	91	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	62	0
27		Materials & Expenses	10.1	1,641	0	1	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 13,202	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	26	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 26	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	1	0
42		Total Sales Expense		$ 7,579	$ 0	$ 1	$ 0
43		Total O & M Expense		$ 137,825,696	$ 101,365	$ 40,813	$ 16,088
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agricultural User Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 68,993	$ 27,778	$ 10,950
2		Interest on Customer Deposits	8.0	958,434	0	0	0
3		Taxes Other Than Income	1.1	58,155,759	76,290	5,572	1,213
4		Total Allocated Operating Deductions		$ 290,748,856	$ 246,648	$ 74,163	$ 28,251
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 62,089	$ 4,535	$ 987
6		South Georgia - Federal	1.1	(15,458,159)	(20,278)	(1,481)	(322)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 4,471,047	$ 294,895	$ 64,213
8		Total Common Systems Allocable Net Plant		95,625,305	125,444	9,162	1,995
9		Cash Working Capital	1.1	(10,297,032)	(7,573)	(3,049)	(1,202)
10		Materials & Supplies	1.1	36,813,908	48,293	3,527	768
11		Prepayments	1.1	7,721,011	10,129	740	161
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(5,943)	0
14		Customer Advances	9.0	(41,613,406)	0	(6,709)	0
15		Deferred Taxes	1.1	(594,534,243)	(779,926)	(56,961)	(12,403)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 3,867,414	$ 235,661	$ 53,532
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 1,232,448	$ 104,880	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	12,754	1,085	0
20		Late Charges	12.0	1,615,145	0	2,012	0
21		Service Establishment Charges	9.0	7,218,698	0	1,164	0
22		Reconnect / Reread Charges	9.0	224,248	0	36	0
23		Other Revenue - Labor	Net Op Margin	4,325	11	1	0
24		Other Revenue - Parts & Material	Net Op Margin	377	1	0	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(0)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	0	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	290	25	0
28		Total Revenue		$ 498,633,048	$ 1,245,504	$ 109,203	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (101,365)	$ (40,813)	$ (16,088)
30		A & G	Total O&M	(93,808,967)	(68,993)	(27,778)	(10,950)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(163,111)	(10,444)	(2,274)
32		Interest on Customer Deposits	8.0	(958,434)	0	0	0
33		Taxes Other Than Income	1.1	(58,155,759)	(76,290)	(5,572)	(1,213)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 835,745	$ 24,597	$ (30,526)
35		Interest Expense	1.1	(47,329,818)	(62,089)	(4,535)	(987)
36		State Taxable Income		$ 47,926,899	$ 773,657	$ 20,062	$ (31,513)
37		State Income Tax	4.90%	$ 2,348,418	$ 37,909	$ 983	$ (1,544)
38		Total State Income Tax		$ 2,348,418	$ 37,909	$ 983	$ (1,544)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 835,745	$ 24,597	$ (30,526)
40		Interest Expense	1.1	(47,329,818)	(62,089)	(4,535)	(987)
41		Federal Taxable Income		$ 47,926,899	$ 773,657	$ 20,062	$ (31,513)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 154,507	$ 4,007	$ (6,293)
43		South Georgia Federal	1.1	(15,458,159)	(20,278)	(1,481)	(322)
44		Total Federal Income Tax		$ (5,886,678)	$ 134,229	$ 2,526	$ (6,616)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 663,607	$ 21,088	$ (22,365)
47		Rate of Return on Rate Base		3.78%	17.16%	8.95%	-41.78%
48		Rate of Return by Class Total				15.93%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Demand	Natural Gas Engine Customer	Natural Gas Engine Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Depreciation Expense & Amortization					
		Direct					
1	301 - 303	Intangible Plant	Intang. Plant	$ 71,779	$ 66	$ 37	$ 5
2	360 - 363.50	Storage Plant	2.0	3,619,500	49,154	0	0
3	374.1 - 387	Distribution Plant	Net Dist. Plant	84,857,013	78,202	43,713	5,497
4	389 - 398	General Plant	1.1	12,828,977	11,823	6,609	831
5		Total Direct Depreciation Expense		$ 101,377,269	$ 139,245	$ 50,359	$ 6,332
		System Allocable Amortization					
6		Miscellaneous Intangible Plant	1.1	$ 10,142,552	$ 9,347	$ 5,225	$ 657
7		General Plant	1.1	4,536,929	4,181	2,337	294
8		Total System Allocable Amortization		$ 14,679,481	$ 13,528	$ 7,562	$ 951
9		Total System Depreciation Expense	1.1	$ 4,536,929	$ 4,181	$ 2,337	$ 294
10		Total Depreciation Expense		$ 116,056,749	$ 152,773	$ 57,920	$ 7,283
11		Amortization Gas Plant Acquisition	1.1	$ 0	$ 0	$ 0	$ 0
12		Regulatory Amortizations	7.0	(3,429,275)	0	(1,017)	0
13		Total Depreciation Expense	1.1	$ (3,429,275)	$ (3,160)	$ (1,767)	$ (222)
14		Total Depreciation & Amortization Expense		$ 112,627,474	$ 149,613	$ 56,154	$ 7,061
		Operation and Maintenance Expense					
		Gas Supply Expenses					
15	803.00	Natural Gas Transmission Line Purchases	3.0	$ 0	$ 0	$ 0	$ 0
16	805.10	Purchased Gas Cost Adjustments	3.0	0	0	0	0
17	810.00	Gas Used for Compression Station Fuel	3.0	0	0	0	0
18	813.00	Other Gas Supply Expenses	3.0	1,358,147	0	0	27,721
19		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 27,721
		Storage					
20	Various	Various	2.0	$ 1,470,088	$ 19,964	$ 0	$ 0
		Distribution Expenses - Operation					
	870.00	Operation Supervision and Engineering					
21		Labor & Labor Loading	5.5	$ 10,008,237	$ 4,177	$ 19,790	$ 3,540
22		Materials & Expenses	5.5	1,448,039	604	2,863	512
	871.00	Distribution Load Dispatching					
23		Labor & Labor Loading	3.0	518,083	0	0	10,574
24		Materials & Expenses	3.0	157,480	0	0	3,214
	874.00	Mains and Services Expenses					
25		Labor & Labor Loading	4.4	4,629,295	4,730	953	0
26		Materials & Expenses	4.4	7,944,286	8,117	1,636	0
	875.00	Measuring & Regulating Exps. - General					
27		Labor & Labor Loading	2.2	1,806,608	2,468	317	0
28		Materials & Expenses	2.2	698,517	954	123	0
	878.00	Meter and House Regulator Expenses					
29		Labor & Labor Loading	6.0	7,566,247	0	24,124	0
30		Materials & Expenses	6.0	3,177,057	0	10,130	0
	879.00	Customer Installation Expense					
31		Labor & Labor Loading	6.0	10,682,646	0	34,060	0
32		Materials & Expenses	6.0	1,798,117	0	5,733	0
	880.00	Other Expenses					
33		Labor & Labor Loading	5.5	6,542,235	2,731	12,937	2,314
34		Materials & Expenses	5.5	6,591,122	2,751	13,033	2,332
35	881.00	Rents	5.5	(724,435)	(302)	(1,432)	(256)
36		Total Distribution Operating Expenses		$ 62,843,534	$ 26,231	$ 124,266	$ 22,231
37		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 46,195	$ 124,266	$ 49,951

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Demand	Natural Gas Engine Customer	Natural Gas Engine Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Maintenance Expenses					
	885.00	Maintenance Supervision & Engineering					
1		Labor & Labor Loading	6.6	$ 2,258,485	$ 1,914	$ 1,029	$ 0
2		Materials & Expenses	6.6	264,999	225	121	0
	886.00	Maintenance of Structures & Improvement					
3		Labor & Labor Loading	1.0	25,812	71	0	0
4		Materials & Expenses	1.0	53,126	145	0	0
	887.00	Maintenance of Mains					
5		Labor & Labor Loading	2.2	11,549,554	15,779	2,026	0
6		Materials & Expenses	2.2	12,648,532	17,281	2,219	0
	889.00	Maintenance of Measuring & Reg. Station Equip.					
7		Labor & Labor Loading	2.2	1,843,201	2,518	323	0
8		Materials & Expenses	2.2	733,457	1,002	129	0
	892.00	Maintenance of Services					
9		Labor & Labor Loading	3.3	5,817,577	0	1,725	0
10		Materials & Expenses	3.3	7,070,213	0	2,096	0
	893.00	Maintenance of Meter & House Regulators					
11		Labor & Labor Loading	6.0	2,429,679	0	7,747	0
12		Materials & Expenses	6.0	1,063,225	0	3,390	0
	894.00	Maintenance of Other Equipment					
13		Labor & Labor Loading	6.6	287,324	244	131	0
14		Materials & Expenses	6.6	73,309	62	33	0
15		Total Distribution-Maintenance		$ 46,118,494	$ 39,241	$ 20,968	$ 0
16		Total Distribution O & M		$ 111,790,263	$ 85,436	$ 145,234	$ 49,951
		Customer Accounts Expenses					
	901.00	Supervision Expenses					
17		Labor & Labor Loading	10.1	$ 1,580,144	$ 0	$ 536	$ 0
18		Materials & Expenses	10.1	262,816	0	89	0
	902.00	Meter Reading Expenses					
19		Labor & Labor Loading	11.0	1,233,010	0	433	0
20		Materials & Expenses	11.0	324,290	0	114	0
	903.00	Customer Records & Collections Expenses					
21		Labor & Labor Loading	4.0	7,055,208	0	2,475	0
22		Materials & Expenses	4.0	12,941,582	0	4,540	0
	903.00	Customer Records & Collections - KAM					
23		Labor & Labor Loading - KAM	15.0	776,052	0	0	0
24		Materials & Expenses - KAM	15.0	2,968	0	0	0
25	904.00	Uncollectible Accounts Expense	4.0	1,350,724	0	474	0
	905.00	Miscellaneous Customer Accounts Expenses					
26		Labor & Labor Loading	10.1	120,054	0	41	0
27		Materials & Expenses	10.1	1,641	0	1	0
28		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 8,702	$ 0
		Customer Service & Informational Expenses					
	908.00	Customer Assistance Expense					
29		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
30		Materials & Expenses	4.0	(21)	0	(0)	0
	909.00	Info. & Instructional Advertising Expense					
31		Labor & Labor Loading	4.0	0	0	0	0
32		Materials & Expenses	4.0	0	0	0	0
	910.00	Misc. Customer Service & Informational Expenses					
33		Labor & Labor Loading	4.0	0	0	0	0
34		Materials & Expenses	4.0	379,388	0	133	0
35		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 133	$ 0
		Sales Expense					
	911.00	Supervision					
36		Labor & Labor Loading	4.0	$ 0	$ 0	$ 0	$ 0
37		Materials & Expenses	4.0	0	0	0	0
	912.00	Demonstrating & Selling Expense					
38		Labor & Labor Loading	4.0	0	0	0	0
39		Materials & Expenses	4.0	0	0	0	0
	913.00	Advertising Expenses					
40		Labor & Labor Loading	4.0	0	0	0	0
41		Materials & Expenses	4.0	7,579	0	3	0
42		Total Sales Expense		$ 7,579	$ 0	$ 3	$ 0
43		Total O & M Expense		$ 137,825,696	$ 85,436	$ 154,071	$ 49,951
44		Allocation Percentage	Total O&M	1	0	0	0

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
EXPENSE ALLOCATION TO CLASSES OF SERVICE
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Demand	Natural Gas Engine Customer	Natural Gas Engine Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Other Operating Deductions					
1		Administrative & General Expense	Total O&M	$ 93,808,967	$ 58,151	$ 104,866	$ 33,999
2		Interest on Customer Deposits	8.0	958,434	0	0	0
3		Taxes Other Than Income	1.1	58,155,759	53,595	29,958	3,767
4		Total Allocated Operating Deductions		$ 290,748,856	$ 197,182	$ 288,896	$ 87,717
		Tax Adjustments					
5		Interest Expense	1.1	$ 47,329,818	$ 43,618	$ 24,381	$ 3,066
6		South Georgia - Federal	1.1	(15,458,159)	(14,246)	(7,963)	(1,001)
		Summary of Allocated Cost of Service					
		Rate Base					
7		Total Direct Net Plant		$ 3,155,975,561	$ 3,895,494	$ 1,585,589	$ 199,374
8		Total Common Systems Allocable Net Plant		95,625,305	88,126	49,260	6,194
9		Cash Working Capital	1.1	(10,297,032)	(6,383)	(11,511)	(3,732)
10		Materials & Supplies	1.1	36,813,908	33,927	18,964	2,385
11		Prepayments	1.1	7,721,011	7,115	3,977	500
12		Other	1.1	0	0	0	0
13		Customer Deposits	9.0	(36,862,844)	0	(5,349)	0
14		Customer Advances	9.0	(41,613,406)	0	(6,038)	0
15		Deferred Taxes	1.1	(594,534,243)	(547,906)	(306,266)	(38,510)
16		Other	1.1	0	0	0	0
17		Total Rate Base		$ 2,612,828,261	$ 3,470,373	$ 1,328,627	$ 166,210
		Revenue					
18		Net Operating Margin	Direct	$ 483,951,321	$ 2,984,891	$ 285,000	$ 0
19		Special Contract & Optional Margin	Net Op Margin	5,008,186	30,889	2,949	0
20		Late Charges	12.0	1,615,145	0	10,117	0
21		Service Establishment Charges	9.0	7,218,698	0	1,047	0
22		Reconnect / Reread Charges	9.0	224,248	0	33	0
23		Other Revenue - Labor	Net Op Margin	4,325	27	3	0
24		Other Revenue - Parts & Material	Net Op Margin	377	2	0	0
25		Other Revenue - Field Collection Fee	Net Op Margin	(21)	(0)	(0)	0
26		Other Revenue - Returned Item Fee	13.0	496,902	0	70	0
27		Other Revenue - Rental Income & UESC Revenue	Net Op Margin	113,867	702	67	0
28		Total Revenue		$ 498,633,048	$ 3,016,511	$ 299,286	$ 0
		Operating Deductions					
29		O & M		$ (137,825,696)	$ (85,436)	$ (154,071)	$ (49,951)
30		A & G	Total O&M	(93,808,967)	(58,151)	(104,866)	(33,999)
31		Depreciation Expense	Deprec Exp	(112,627,474)	(149,613)	(56,154)	(7,061)
32		Interest on Customer Deposits	8.0	(958,434)	0	0	0
33		Taxes Other Than Income	1.1	(58,155,759)	(53,595)	(29,958)	(3,767)
		State Income Tax					
34		Taxable Income before Interest Expense		$ 95,256,717	$ 2,669,717	$ (45,764)	$ (94,778)
35		Interest Expense	1.1	(47,329,818)	(43,618)	(24,381)	(3,066)
36		State Taxable Income		$ 47,926,899	$ 2,626,099	$ (70,145)	$ (97,844)
37		State Income Tax	4.90%	$ 2,348,418	$ 128,679	$ (3,437)	$ (4,794)
38		Total State Income Tax		$ 2,348,418	$ 128,679	$ (3,437)	$ (4,794)
		Federal Income Tax					
39		Taxable Income before Interest Expense		$ 95,256,717	$ 2,669,717	$ (45,764)	$ (94,778)
40		Interest Expense	1.1	(47,329,818)	(43,618)	(24,381)	(3,066)
41		Federal Taxable Income		$ 47,926,899	$ 2,626,099	$ (70,145)	$ (97,844)
42		Federal Income Tax	19.97%	$ 9,571,481	$ 524,458	$ (14,009)	$ (19,540)
43		South Georgia Federal	1.1	(15,458,159)	(14,246)	(7,963)	(1,001)
44		Total Federal Income Tax		$ (5,886,678)	$ 510,213	$ (21,972)	$ (20,542)
45		Regulatory Amortization	1.1	$ 0	$ 0	$ 0	$ 0
46		Net Income		$ 98,794,977	$ 2,030,826	$ (20,355)	$ (69,442)
47		Rate of Return on Rate Base		3.78%	58.52%	-1.53%	-41.78%
48		Rate of Return by Class Total				39.09%	

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DISTRIBUTION OF RATE BASE BY FUNCTION - DATA ENTRY AND CLASSIFICATION OF COSTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line	Acct				Storage				Distribution				Line
No.	No.	Description	Allocation	Amount	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
		Cost of Service											
		Direct											
		Intangible Plant											
1	301.00	Organization	Dist Plant	$ 42,653	$ 0	$ 0	$ 0	$ 0	$ 0	$ 14,385	$ 28,132	$ 135	1
2	302.00	Franchises & Consents	Dist Plant	1,167,977	0	0	0	0	0	393,921	770,349	3,707	2
3	303.00	Miscellaneous Intangible Plant	Dist Plant	0	0	0	0	0	0	0	0	0	3
4		Total Direct Intangible Plant		$ 1,210,630	$ 0	$ 0	$ 0	$ 0	$ 0	$ 408,307	$ 798,481	$ 3,842	4
		Storage Plant											
5	360.00	Land and Land Rights		$ 1,772,673	$ 0	$ 1,772,673	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	5
6	361.00	Structures and Improvements		76,200,000	0	76,200,000	0	0	0	0	0	0	6
7	363.10	Liquifaction Equipment		0	0	0	0	0	0	0	0	0	7
8	363.20	Vaporizing Equipment		0	0	0	0	0	0	0	0	0	8
9	363.30	Compressor Equipment		0	0	0	0	0	0	0	0	0	9
10	363.50	Other Equipment		0	0	0	0	0	0	0	0	0	10
11		Total Storage Plant		$ 77,972,673	$ 0	$ 77,972,673	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	11
		Distribution Plant											
12	374.10	Land & Land Rights	Demand	$ 405,666	$ 0	$ 0	$ 0	$ 0	$ 0	$ 405,666	$ 0	$ 0	12
13	374.20	Rights of Way	Demand	2,332,188	0	0	0	0	0	2,332,188	0	0	13
14	375.00	Structures	Demand	457,330	0	0	0	0	0	457,330	0	0	14
15	376.00	Mains	Dmd/Cust	1,907,528,579	0	0	0	0	0	953,764,290	953,764,290	0	15
16	378.00	Measuring & Regulating Station	Commodity	65,754,717	0	0	0	0	0	32,877,358	32,877,358	0	16
17	380.00	Services	Customer	643,127,744	0	0	0	0	0	0	643,127,744	0	17
18	381.00	Meters	Customer	305,766,590	0	0	0	0	0	0	305,766,590	0	18
19	385.00	Industrial Measuring & Regulating Station	Commodity	9,313,055	0	0	0	0	0	0	0	9,313,055	19
20	387.00	Other Equipment	Demand	(92,997)	0	0	0	0	0	(92,997)	0	0	20
21		Total Direct Distribution Plant		$ 2,934,592,871	$ 0	$ 0	$ 0	$ 0	$ 0	$ 989,743,835	$ 1,935,535,982	$ 9,313,055	21
22		Total Percent Direct Distribution Plant		100.00%	0%	0%	0%	0%	0%	34%	66%	0%	22
		General Plant											
23	389.00	Land & Land Rights	Dist Plant	$ 17,352,123	$ 0	$ 0	$ 0	$ 0	$ 0	$ 5,852,313	$ 11,444,742	$ 55,068	23
24	390.10	Structures	Dist Plant	63,571,857	0	0	0	0	0	21,440,744	41,929,365	201,748	24
25	390.20	Structures - Leasehold Improvements	Dist Plant	111,993	0	0	0	0	0	37,772	73,866	355	25
26	391.00	Office Furniture & Equipment	Dist Plant	4,015,366	0	0	0	0	0	1,354,254	2,648,369	12,743	26
27	391.10	Computer Equipment	Dist Plant	11,979,259	0	0	0	0	0	4,040,219	7,901,023	38,017	27
28	392.11	Transportation Equipment - Light	Dist Plant	12,530,277	0	0	0	0	0	4,226,060	8,264,452	39,765	28
29	392.20	Transportation Equipment - Heavy	Dist Plant	9,820,190	0	0	0	0	0	3,312,034	6,476,991	31,165	29
30	393.00	Stores Equipment	Dist Plant	637,178	0	0	0	0	0	214,900	420,256	2,022	30
31	394.00	Tools, Shop & Garage Equipment	Dist Plant	11,251,584	0	0	0	0	0	3,794,797	7,421,079	35,707	31
32	395.00	Laboratory Equipment	Dist Plant	391,969	0	0	0	0	0	132,199	258,527	1,244	32
33	396.00	Power Operated Equipment	Dist Plant	5,897,959	0	0	0	0	0	1,989,192	3,890,049	18,717	33
34	397.10	Communication Equipment	Dist Plant	2,956,333	0	0	0	0	0	997,076	1,949,875	9,382	34
35	397.20	Telemetering Equipment	Dist Plant	(9,905)	0	0	0	0	0	(3,341)	(6,533)	(31)	35
36	398.00	Miscellaneous Equipment	Dist Plant	1,693,203	0	0	0	0	0	571,063	1,116,767	5,373	36
37		Total Direct General Plant		$ 142,199,386	$ 0	$ 0	$ 0	$ 0	$ 0	$ 47,959,282	$ 93,788,829	$ 451,276	37
		Common - Systems Allocable											
		Intangible Plant											
38	301.00	Organization	Dist Plant	$ 34,418	$ 0	$ 0	$ 0	$ 0	$ 0	$ 11,608	$ 22,701	$ 109	38
39	303.00	Miscellaneous Intangible	Dist Plant	40,705,487	0	0	0	0	0	13,728,652	26,847,654	129,181	39
40		Total Common Intangible Plant		$ 40,739,905	$ 0	$ 0	$ 0	$ 0	$ 0	$ 13,740,260	$ 26,870,355	$ 129,290	40
		General Plant											
41	389.00	Land & Land Rights	Dist Plant	$ 3,465,350	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,168,751	$ 2,285,602	$ 10,997	41
42	390.10	Structures	Dist Plant	28,877,414	0	0	0	0	0	9,739,424	19,046,347	91,644	42
43	390.20	Structures - Leasehold Improvements	Dist Plant	1,600,119	0	0	0	0	0	539,669	1,055,372	5,078	43
44	391.00	Office Furniture & Equipment	Dist Plant	2,921,563	0	0	0	0	0	985,349	1,926,942	9,272	44
45	391.10	Computer Equipment	Dist Plant	8,489,068	0	0	0	0	0	2,863,090	5,599,038	26,940	45
46	392.11	Transportation Equipment - Light	Dist Plant	1,507,206	0	0	0	0	0	508,332	994,091	4,783	46
47	392.21	Transportation Equipment - Aircraft	Dist Plant	3,028,440	0	0	0	0	0	1,021,395	1,997,434	9,611	47
48	393.00	Stores Equipment	Dist Plant	18,480	0	0	0	0	0	6,233	12,189	59	48
49	394.00	Tools, Shop & Garage Equipment	Dist Plant	388,880	0	0	0	0	0	131,157	256,489	1,234	49
50	395.00	Laboratory Equipment	Dist Plant	547,348	0	0	0	0	0	184,603	361,008	1,737	50
51	396.00	Power Operated Equipment	Dist Plant	8,820	0	0	0	0	0	2,975	5,817	28	51
52	397.00	Communication Equipment	Dist Plant	2,553,297	0	0	0	0	0	861,145	1,684,049	8,103	52
53	397.20	Telemetering Equipment	Dist Plant	(10,255)	0	0	0	0	0	(3,459)	(6,763)	(33)	53
54	398.00	Miscellaneous Equipment	Dist Plant	1,489,670	0	0	0	0	0	502,418	982,524	4,728	54
55		Total Common General Plant		$ 54,885,400	$ 0	$ 0	$ 0	$ 0	$ 0	$ 18,511,081	$ 36,200,138	$ 174,181	55
		Net Plant											
56		Total Direct Net Plant		$ 3,155,975,561	$ 0	$ 77,972,673	$ 0	$ 0	$ 0	$ 1,038,111,423	$ 2,030,123,293	$ 9,768,172	56
57		Total Common/System Allocable Net Plant	4.90%	95,625,305	0	0	0	0	0	32,251,341	63,070,493	303,471	57
58		Total Net Plant		$ 3,251,600,867	$ 0	$ 77,972,673	$ 0	$ 0	$ 0	$ 1,070,362,764	$ 2,093,193,786	$ 10,071,643	58
		Rate Base											
59		Cash Working Capital	Net Plant	$ (10,297,032)	$ 0	$ (246,921)	$ 0	$ 0	$ 0	$ (3,389,579)	$ (6,628,637)	$ (31,894)	59
60		Materials & Supplies	Net Plant	36,813,908	0	882,789	0	0	0	12,118,411	23,698,678	114,029	60
61		Prepayments	Net Plant	7,721,011	0	185,148	0	0	0	2,541,604	4,970,343	23,915	61
62		Other		0	0	0	0	0	0	0	0	0	62
63		Customer Advances	Customer	(41,613,406)	0	(997,880)	0	0	0	(13,698,311)	(26,788,319)	(128,895)	63
64		Customer Deposits	Customer	(36,862,844)	0	(883,963)	0	0	0	(12,134,520)	(23,730,181)	(114,181)	64
65		Deferred Taxes	Net Plant	(594,534,243)	0	(14,256,800)	0	0	0	(195,708,927)	(382,726,981)	(1,841,535)	65
66		Other		0	0	0	0	0	0	0	0	0	66
67		Total Rate Base		$ 2,612,828,261	$ 0	$ 62,655,047	$ 0	$ 0	$ 0	$ 860,091,443	$ 1,681,988,689	$ 8,093,083	67

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DISTRIBUTION OF EXPENSES BY FUNCTION - DATA ENTRY AND CLASSIFICATION OF COSTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line	Acct				Storage				Distribution				Customer Accounting			Line
No.	No.	Description	Allocation	Amount	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
		Depreciation Expense & Amortization														
		Direct														
		Intangible Plant														
1	301.00	Organization		0	0	0	0	0	0	0	0	0	0	0	0	1
2	302.00	Franchises & Consents	Plant Acct.	71,779	0	0	0	0	0	24,209	47,342	228	0	0	0	2
3	303.00	Miscellaneous Intangible Plant		0	0	0	0	0	0	0	0	0	0	0	0	3
4		Total Direct Intangible Plant		$ 71,779	$ 0	$ 0	$ 0	$ 0	$ 0	$ 24,209	$ 47,342	$ 228	$ 0	$ 0	$ 0	4
		Storage Plant														
5	360.00	Land and Land Rights	Plant Acct.	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	5
6	361.00	Structures and Improvements	Plant Acct.	3,619,500	0	3,619,500	0	0	0	0	0	0	0	0	0	6
7	363.10	Liquifaction Equipment	Plant Acct.	0	0	0	0	0	0	0	0	0	0	0	0	7
8	363.20	Vaporizing Equipment	Plant Acct.	0	0	0	0	0	0	0	0	0	0	0	0	8
9	363.30	Compressor Equipment	Plant Acct.	0	0	0	0	0	0	0	0	0	0	0	0	9
10	363.50	Other Equipment	Plant Acct.	0	0	0	0	0	0	0	0	0	0	0	0	10
11		Total Storage Plant		$ 3,619,500	$ 0	$ 3,619,500	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	11
		Distribution Plant														
12	374.10	Land & Land Rights		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13	374.20	Rights of Way	Plant Acct.	0	0	0	0	0	0	0	0	0	0	0	0	13
14	375.00	Structures	Plant Acct.	45,380	0	0	0	0	0	45,380	0	0	0	0	0	14
15	376.00	Mains	Plant Acct.	3,704	0	0	0	0	0	1,852	1,852	0	0	0	0	15
16	378.00	Measuring & Regulating Station	Plant Acct.	39,101,233	0	0	0	0	0	19,550,617	19,550,617	0	0	0	0	16
17	380.00	Services	Plant Acct.	3,276,991	0	0	0	0	0	0	3,276,991	0	0	0	0	17
18	381.00	Meters	Plant Acct.	29,444,796	0	0	0	0	0	0	29,444,796	0	0	0	0	18
19	385.00	Industrial Measuring & Regulating Station	Plant Acct.	12,763,384	0	0	0	0	0	0	0	12,763,384	0	0	0	19
20	387.00	Other Equipment	Plant Acct.	221,524	0	0	0	0	0	221,524	0	0	0	0	0	20
21		Total Direct Distribution Plant		$ 84,857,013	$ 0	$ 0	$ 0	$ 0	$ 0	$ 19,819,372	$ 52,274,256	$ 12,763,384	$ 0	$ 0	$ 0	21
		General Plant														
22	389.00	Land & Land Rights		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	22
23	390.10	Structures	Plant Acct.	2,047,787	0	0	0	0	0	690,653	1,350,636	6,499	0	0	0	23
24	390.20	Structures - Leasehold Improvements	Plant Acct.	8,221	0	0	0	0	0	2,773	5,422	26	0	0	0	24
25	391.00	Office Furniture & Equipment	Plant Acct.	432,749	0	0	0	0	0	145,952	285,423	1,373	0	0	0	25
26	391.10	Computer Equipment	Plant Acct.	3,878,400	0	0	0	0	0	1,308,059	2,558,032	12,308	0	0	0	26
27	392.11	Transportation Equipment - Light	Plant Acct.	3,541,001	0	0	0	0	0	1,194,266	2,335,498	11,238	0	0	0	27
28	392.12	Transportation Equipment - Heavy	Plant Acct.	692,081	0	0	0	0	0	233,417	456,468	2,196	0	0	0	28
29	393.00	Stores Equipment	Plant Acct.	35,029	0	0	0	0	0	11,814	23,104	111	0	0	0	29
30	394.00	Tools, Shop & Garage Equipment	Plant Acct.	1,717,453	0	0	0	0	0	579,242	1,132,761	5,450	0	0	0	30
31	395.00	Laboratory Equipment	Plant Acct.	30,534	0	0	0	0	0	10,298	20,139	97	0	0	0	31
32	396.00	Power Operated Equipment	Plant Acct.	311,637	0	0	0	0	0	105,105	205,543	989	0	0	0	32
33	397.10	Communication Equipment	Plant Acct.	(35,460)	0	0	0	0	0	(11,960)	(23,388)	(113)	0	0	0	33
34	397.20	Telemetering Equipment	Plant Acct.	35,990	0	0	0	0	0	12,138	23,737	114	0	0	0	34
35	398.00	Miscellaneous Equipment	Plant Acct.	133,556	0	0	0	0	0	45,044	88,088	424	0	0	0	35
36		Total Direct General Plant		$ 12,828,977	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,326,802	$ 8,461,462	$ 40,713	$ 0	$ 0	$ 0	36
		Common - Systems Allocable														
		Common - Systems Allocation	4.90%													
		Intangible Plant														
37	301.00	Organization		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	37
38	303.00	Miscellaneous Intangible	Plant Acct.	10,142,552	0	0	0	0	0	3,420,757	6,689,608	32,188	0	0	0	38
39		Total Common Intangible Plant		$ 10,142,552	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,420,757	$ 6,689,608	$ 32,188	$ 0	$ 0	$ 0	39

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DISTRIBUTION OF EXPENSES BY FUNCTION - DATA ENTRY AND CLASSIFICATION OF COSTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Acct No.	Description	Allocation	Amount	Storage Specific	Storage Demand	Storage Customer	Storage Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
		General Plant														
1	389.00	Land & Land Rights		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2	390.10	Structures	Plant Acct.	674,214	0	0	0	0	0	227,391	444,683	2,140	0	0	0	2
3	390.20	Structures - Leasehold Improvements	Plant Acct.	298,476	0	0	0	0	0	100,666	196,862	947	0	0	0	3
4	391.00	Office Furniture & Equipment	Plant Acct.	347,367	0	0	0	0	0	117,156	229,109	1,102	0	0	0	4
5	391.10	Computer Equipment	Plant Acct.	2,401,053	0	0	0	0	0	809,798	1,583,635	7,620	0	0	0	5
6	392.11	Transportation Equipment, Light	Plant Acct.	163,984	0	0	0	0	0	55,307	108,157	520	0	0	0	6
7	392.12	Transportation Equipment, Heavy	Plant Acct.	0	0	0	0	0	0	0	0	0	0	0	0	7
8	392.21	Transportation Equipment, Aircraft	Plant Acct.	183,099	0	0	0	0	0	61,753	120,764	581	0	0	0	8
9	393.00	Stores Equipment	Plant Acct.	2,341	0	0	0	0	0	790	1,544	7	0	0	0	9
10	394.00	Tools, Shop & Garage Equipment	Plant Acct.	41,085	0	0	0	0	0	13,857	27,098	130	0	0	0	10
11	395.00	Laboratory Equipment	Plant Acct.	35,158	0	0	0	0	0	11,858	23,189	112	0	0	0	11
12	396.00	Power Operated Equipment	Plant Acct.	371	0	0	0	0	0	125	245	1	0	0	0	12
13	397.00	Communication Equipment	Plant Acct.	277,352	0	0	0	0	0	93,542	182,930	880	0	0	0	13
14	397.20	Telemetering Equipment	Plant Acct.	208	0	0	0	0	0	70	137	1	0	0	0	14
15	398.00	Miscellaneous Equipment	Plant Acct.	112,220	0	0	0	0	0	37,848	74,016	356	0	0	0	15
16		Total Common General Plant		$ 4,536,929	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,530,160	$ 2,992,370	$ 14,398	$ 0	$ 0	$ 0	16
		System Allocable Amortization														
17	303.00	Miscellaneous Intangible Plant	Com Gen Plant	$ 10,142,552	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,420,757	$ 6,689,608	$ 32,188	$ 0	$ 0	$ 0	17
18	309.2-398	General Plant	Com Gen Plant	4,536,929	0	0	0	0	0	1,530,160	2,992,370	14,398	0	0	0	18
19		Total System Allocable Amortization		$ 14,679,481	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,950,917	$ 9,681,978	$ 46,586	$ 0	$ 0	$ 0	19
20	389-390.1	Total System Depreciation Expense	Com Gen Plant	$ 4,536,929	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,530,160	$ 2,992,370	$ 14,398	$ 0	$ 0	$ 0	20
21		Total Direct Depreciation Expense	Dir. Depr.	101,377,269	0	3,619,500	0	0	0	24,170,383	60,783,061	12,804,325	0	0	0	21
22		Amortization Gas Plant Acquisition	Dir. Depr.	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	22
23		Regulatory Amortizations	Dir. Depr.	$ (3,429,275)	0	(122,436)	0	0	0	(817,608)	(2,056,100)	(433,130)	0	0	0	23
24		Total Depreciation Expense		$ 112,627,474	$ 0	$ 3,497,064	$ 0	$ 0	$ 0	$ 28,303,691	$ 68,408,938	$ 12,417,781	$ 0	$ 0	$ 0	24
		Operation and Maintenance Expense														
		Operation Expenses														
		Gas Supply Expenses														
25	803.00	Natural Gas Transmission Line Purchases		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	805.10	Purchased Gas Cost Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	26
27	810.00	Gas Used for Compression Station Fuel		0	0	0	0	0	0	0	0	0	0	0	0	27
	813.00	Other Gas Supply Expenses														
28		Labor	Commodity	$ 777,658	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 777,658	$ 0	$ 0	$ 0	28
29		Labor Loadings	Commodity	436,371	0	0	0	0	0	0	0	436,371	0	0	0	29
30		Materials & Expenses	Commodity	144,118	0	0	0	0	0	0	0	144,118	0	0	0	30
31		Total Gas Supply Expenses		$ 1,358,147	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,358,147	$ 0	$ 0	$ 0	31

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DISTRIBUTION OF EXPENSES BY FUNCTION - DATA ENTRY AND CLASSIFICATION OF COSTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line	Acct				Storage				Distribution				Customer Accounting			Line
No.	No.	Description	Allocation	Amount	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
		Transmission Expenses														
	858.00	Transmission and Compression of Gas														
1		Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2		Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	2
3		Materials & Expenses		0	0	0	0	0	0	0	0	0	0	0	0	3
4		Total Transmission Expenses		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	4
		Storage														
5	Various	Various		$ 1,470,088	$ 0	$ 1,470,088	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	5
		Distribution Expenses - Operation														
	870.00	Operation Supervision and Engineering														
6		Labor	Dist Oper Exp	$ 6,400,906	$ 0	$ 0	$ 0	$ 0	$ 0	$ 827,556	$ 5,106,496	$ 466,854	$ 0	$ 0	$ 0	6
7		Labor Loadings	Dist Oper Exp	3,607,331	0	0	0	0	0	466,382	2,877,846	263,103	0	0	0	7
8		Materials & Expenses	Dist Oper Exp	1,448,039	0	0	0	0	0	187,213	1,155,213	105,614	0	0	0	8
	871.00	Distribution Load Dispatching														
9		Labor	Dmd/Comm	$ 331,464	$ 0	$ 0	$ 0	$ 0	$ 0	$ 165,732	$ 0	$ 165,732	$ 0	$ 0	$ 0	9
10		Labor Loadings	Dmd/Comm	186,619	0	0	0	0	0	93,309	0	93,309	0	0	0	10
11		Materials & Expenses	Dmd/Comm	157,480	0	0	0	0	0	78,740	0	78,740	0	0	0	11
	874.00	Mains and Services Expenses														
12		Labor	Plant Acct.	$ 2,967,620	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,109,679	$ 1,857,941	$ 0	$ 0	$ 0	$ 0	12
13		Labor Loadings	Plant Acct.	1,661,675	0	0	0	0	0	621,348	1,040,326	0	0	0	0	13
14		Materials & Expenses	Plant Acct.	7,944,286	0	0	0	0	0	2,970,599	4,973,687	0	0	0	0	14
	875.00	Measuring & Regulating Exps. - General														
15		Labor	Commodity	$ 1,151,572	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,151,572	$ 0	$ 0	$ 0	15
16		Labor Loadings	Commodity	655,035	0	0	0	0	0	0	0	655,035	0	0	0	16
17		Materials & Expenses	Commodity	698,517	0	0	0	0	0	0	0	698,517	0	0	0	17
	878.00	Meter and House Regulator Expenses														
18		Labor	Plant Acct.	$ 4,861,745	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,861,745	$ 0	$ 0	$ 0	$ 0	18
19		Labor Loadings	Plant Acct.	2,704,502	0	0	0	0	0	0	2,704,502	0	0	0	0	19
20		Materials & Expenses	Plant Acct.	3,177,057	0	0	0	0	0	0	3,177,057	0	0	0	0	20
	879.00	Customer Installation Expense														
21		Labor	Dist Cust	$ 6,866,887	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 6,866,887	$ 0	$ 0	$ 0	$ 0	21
22		Labor Loadings	Dist Cust	3,815,759	0	0	0	0	0	0	3,815,759	0	0	0	0	22
23		Materials & Expenses	Dist Cust	1,798,117	0	0	0	0	0	0	1,798,117	0	0	0	0	23
	880.00	Other Expenses														
24		Labor	Dist Oper Exp	$ 4,168,772	$ 0	$ 0	$ 0	$ 0	$ 0	$ 538,970	$ 3,325,750	$ 304,052	$ 0	$ 0	$ 0	24
25		Labor Loadings	Dist Oper Exp	2,373,463	0	0	0	0	0	306,859	1,893,495	173,110	0	0	0	25
26		Materials & Expenses	Dist Oper Exp	6,591,122	0	0	0	0	0	852,149	5,258,246	480,727	0	0	0	26
	881.00	Rents														
27		Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	27
28		Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	28
29		Materials & Expenses	Dist Oper Exp	(724,435)	0	0	0	0	0	(93,660)	(577,938)	(52,837)	0	0	0	29
30		Total Distribution Operating Expenses		$ 62,843,534	$ 0	$ 0	$ 0	$ 0	$ 0	$ 8,124,876	$ 50,135,130	$ 4,583,527	$ 0	$ 0	$ 0	30
31		Total Gas Supply & Distribution Expenses		$ 65,671,769	$ 0	$ 1,470,088	$ 0	$ 0	$ 0	$ 8,124,876	$ 50,135,130	$ 5,941,674	$ 0	$ 0	$ 0	31

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DISTRIBUTION OF EXPENSES BY FUNCTION - DATA ENTRY AND CLASSIFICATION OF COSTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line	Acct				Storage				Distribution				Customer Accounting			Line
No.	No.	Description	Allocation	Amount	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
		Maintenance Expenses														
	885.00	Maintenance Supervision & Engineering														
1		Labor	Dist Maint Exp	$ 1,447,971	$ 0	$ 0	$ 0	$ 0	$ 0	$ 407,855	$ 953,820	$ 86,295	$ 0	$ 0	$ 0	1
2		Labor Loadings	Dist Maint Exp	810,514	0	0	0	0	0	228,300	533,909	48,305	0	0	0	2
3		Materials & Expenses	Dist Maint Exp	264,999	0	0	0	0	0	74,643	174,562	15,793	0	0	0	3
	886.00	Maintenance of Structures & Improvement														
4		Labor	Plant Acct.	$ 16,085	$ 0	$ 0	$ 0	$ 0	$ 0	$ 16,085	$ 0	$ 0	$ 0	$ 0	$ 0	4
5		Labor Loadings	Plant Acct.	9,727	0	0	0	0	0	9,727	0	0	0	0	0	5
6		Materials & Expenses	Plant Acct.	53,126	0	0	0	0	0	53,126	0	0	0	0	0	6
	887.00	Maintenance of Mains														
7		Labor	Plant Acct.	$ 7,377,201	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,688,600	$ 3,688,600	$ 0	$ 0	$ 0	$ 0	7
8		Labor Loadings	Plant Acct.	4,172,353	0	0	0	0	0	2,086,177	2,086,177	0	0	0	0	8
9		Materials & Expenses	Plant Acct.	12,648,532	0	0	0	0	0	6,324,266	6,324,266	0	0	0	0	9
	889.00	Maint. of Measuring & Reg. Station Equip.														
10		Labor	Commodity	$ 1,179,167	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,179,167	$ 0	$ 0	$ 0	10
11		Labor Loadings	Commodity	664,034	0	0	0	0	0	0	0	664,034	0	0	0	11
12		Materials & Expenses	Commodity	733,457	0	0	0	0	0	0	0	733,457	0	0	0	12
	892.00	Maintenance of Services														
13		Labor	Plant Acct.	$ 3,708,133	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,708,133	$ 0	$ 0	$ 0	$ 0	13
14		Labor Loadings	Plant Acct.	2,109,444	0	0	0	0	0	0	2,109,444	0	0	0	0	14
15		Materials & Expenses	Plant Acct.	7,070,213	0	0	0	0	0	0	7,070,213	0	0	0	0	15
	893.00	Maintenance of Meter & House Regulators														
16		Labor	Plant Acct.	$ 1,563,904	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,563,904	$ 0	$ 0	$ 0	$ 0	16
17		Labor Loadings	Plant Acct.	865,775	0	0	0	0	0	0	865,775	0	0	0	0	17
18		Materials & Expenses	Plant Acct.	1,063,225	0	0	0	0	0	0	1,063,225	0	0	0	0	18
	894.00	Maintenance of Other Equipment														
19		Labor	Dist Maint Exp	$ 183,812	$ 0	$ 0	$ 0	$ 0	$ 0	$ 51,775	$ 121,082	$ 10,955	$ 0	$ 0	$ 0	19
20		Labor Loadings	Dist Maint Exp	103,512	0	0	0	0	0	29,157	68,186	6,169	0	0	0	20
21		Materials & Expenses	Dist Maint Exp	73,309	0	0	0	0	0	20,649	48,291	4,369	0	0	0	21
22		Total Maintenance Expenses		$ 46,118,494	$ 0	$ 0	$ 0	$ 0	$ 0	$ 12,990,361	$ 30,379,589	$ 2,748,544	$ 0	$ 0	$ 0	22
23		Total Gas Supply, Distribution & Maint. Exps		$ 111,790,263	$ 0	$ 1,470,088	$ 0	$ 0	$ 0	$ 21,115,237	$ 80,514,719	$ 8,690,219	$ 0	$ 0	$ 0	23
		Customer Accounts Expenses														
	901.00	Supervision Expenses														
24		Labor	Customer	$ 1,013,793	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,013,793	24
25		Labor Loadings	Customer	566,351	0	0	0	0	0	0	0	0	0	0	566,351	25
26		Materials & Expenses	Customer	262,816	0	0	0	0	0	0	0	0	0	0	262,816	26
	902.00	Meter Reading Expenses														
27		Labor	Customer	$ 788,653	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 788,653	27
28		Labor Loadings	Customer	444,357	0	0	0	0	0	0	0	0	0	0	444,357	28
29		Materials & Expenses	Customer	324,290	0	0	0	0	0	0	0	0	0	0	324,290	29

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DISTRIBUTION OF EXPENSES BY FUNCTION - DATA ENTRY AND CLASSIFICATION OF COSTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line	Acct				Storage				Distribution				Customer Accounting			Line
No.	No.	Description	Allocation	Amount	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
	903.00	Customer Records & Collections Expenses														
1		Labor & Loadings	KAM Direct	776,052	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 776,052	1
2		Materials & Expenses	KAM Direct	2,968	0	0	0	0	0	0	0	0	0	0	2,968	2
	903.00	Customer Records & Collections Expenses														
3		Labor & Loadings	Customer	$ 7,055,208	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 7,055,208	3
4		Materials & Expenses	Customer	12,941,581.51	0	0	0	0	0	0	0	0	0	0	12,941,582	4
	904.00	Uncollectible Accounts Expense														
5		Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	5
6		Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	6
7		Materials & Expenses	Customer	1,350,724	0	0	0	0	0	0	0	0	0	0	1,350,724	7
	905.00	Miscellaneous Customer Accounts Expenses														
8		Labor	Customer	$ 75,975	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 75,975	8
9		Labor Loadings	Customer	44,079	0	0	0	0	0	0	0	0	0	0	44,079	9
10		Materials & Expenses	Customer	1,641	0	0	0	0	0	0	0	0	0	0	1,641	10
11		Total Customer Accounts Expenses		$ 25,648,489	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 25,648,489	11
		Customer Service & Informational Expenses														
	908.00	Customer Assistance Expense														
12		Labor	Customer	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13		Labor Loadings	Customer	0	0	0	0	0	0	0	0	0	0	0	0	13
14		Materials & Expenses	Customer	(21)	0	0	0	0	0	0	0	0	0	0	(21)	14
	909.00	Info. & Instructional Advertising Exps.														
15		Labor	Customer	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	15
16		Labor Loadings	Customer	0	0	0	0	0	0	0	0	0	0	0	0	16
17		Materials & Expenses		0	0	0	0	0	0	0	0	0	0	0	0	17
	910.00	Misc. Customer Service & Info. Exp.														
18		Labor	Customer	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	18
19		Labor Loadings	Customer	0	0	0	0	0	0	0	0	0	0	0	0	19
20		Materials & Expenses	Customer	379,388	0	0	0	0	0	0	0	0	0	0	379,388	20
21		Total Customer Service & Informational Expenses		$ 379,366	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 379,366	21
		Sales Expense														
	911.00	Supervision														
22		Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	22
23		Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	23
24		Materials & Expenses		0	0	0	0	0	0	0	0	0	0	0	0	24

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DISTRIBUTION OF EXPENSES BY FUNCTION - DATA ENTRY AND CLASSIFICATION OF COSTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Acct No.	Description	Allocation	Amount	Storage Specific	Storage Demand	Storage Customer	Storage Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
	912.00	Demonstrating & Selling Expense														
1		Labor		0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2		Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	2
3		Materials & Expenses		0	0	0	0	0	0	0	0	0	0	0	0	3
	913.00	Advertising Expenses														
4		Labor		0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	4
5		Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	5
6		Materials & Expenses	Customer	7,579	0	0	0	0	0	0	0	0	0	0	7,579	6
7		Total Sales Expense		$ 7,579	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 7,579	7
8		Total O&M Expense		$ 137,825,696	$ 0	$ 1,470,088	$ 0	$ 0	$ 0	$ 21,115,237	$ 80,514,719	$ 8,690,219	$ 0	$ 0	$ 26,035,434	8
										15%	58%	6%			19%	
		Administrative & General Expense														
	920.00	Administrative & General Salaries														
9		Labor	Total O&M	$ 35,649,057	$ 0	$ 380,243	$ 0	$ 0	$ 0	$ 5,461,524	$ 20,825,390	$ 2,247,753	$ 0	$ 0	$ 6,734,148	9
10		Labor Loadings	Total O&M	16,186,762	0	172,653	0	0	0	2,479,852	9,455,948	1,020,612	0	0	3,057,698	10
11		Materials & Expenses	Total O&M	(2,175,262)	0	(23,202)	0	0	0	(333,255)	(1,270,740)	(137,155)	0	0	(410,909)	11
12		Total Admin. & General Salaries		$ 49,660,558	$ 0	$ 529,694	$ 0	$ 0	$ 0	$ 7,608,120	$ 29,010,598	$ 3,131,209	$ 0	$ 0	$ 9,380,937	12
		Other Administrative & General Expense														
13	921.00	Office Supplies	Total O&M	$ 8,654,058	$ 0	$ 92,307	$ 0	$ 0	$ 0	$ 1,325,823	$ 5,055,509	$ 545,658	$ 0	$ 0	$ 1,634,762	13
14	922.00	Administrative Expenses Transferred - Credit	Total O&M	(8,446,298)	0	(90,091)	0	0	0	(1,293,994)	(4,934,140)	(532,558)	0	0	(1,595,515)	14
15	923.00	Outside Services Employed	Total O&M	14,523,045	0	154,907	0	0	0	2,224,966	8,484,041	915,711	0	0	2,743,420	15
16	924.00	Property Insurance	Total O&M	248,977	0	2,656	0	0	0	38,144	145,447	15,699	0	0	47,032	16
17	925.00	Injuries and Damages	Total O&M	7,941,638	0	84,708	0	0	0	1,216,679	4,639,329	500,738	0	0	1,500,185	17
18	926.00	Employee Pensions and Benefits	Total O&M	9,862,398	0	105,195	0	0	0	1,510,944	5,761,394	621,846	0	0	1,863,018	18
19	928.00	Regulatory Commission Expenses	Total O&M	157,000	0	1,675	0	0	0	24,053	91,716	9,899	0	0	29,657	19
20	930.10	Safety Advertising	Total O&M	962,067	0	10,262	0	0	0	147,391	562,018	60,660	0	0	181,736	20
	930.20	Miscellaneous General Expenses														
21		Labor	Total O&M	0	0	0	0	0	0	0	0	0	0	0	0	21
22		Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	22
23		Materials & Expenses	Total O&M	4,144,041	0	44,202	0	0	0	634,877	2,420,857	261,291	0	0	782,814	23
24	931.00	Rents	Total O&M	1,871,601	0	19,963	0	0	0	286,734	1,093,348	118,009	0	0	353,548	24
	935.00	Maintenance of General Plant														
25		Labor	Total O&M	726,355	0	7,748	0	0	0	111,279	424,321	45,798	0	0	137,209	25
26		Labor Loadings	Total O&M	420,540	0	4,486	0	0	0	64,428	245,670	26,516	0	0	79,440	26
27		Materials & Expenses	Total O&M	3,082,987	0	32,884	0	0	0	472,321	1,801,013	194,389	0	0	582,380	27
28		Total Other Administrative & General Expense		$ 44,148,409	$ 0	$ 470,899	$ 0	$ 0	$ 0	$ 6,763,645	$ 25,790,523	$ 2,783,656	$ 0	$ 0	$ 8,339,686	28
29		Total Administrative and General Expense		$ 93,808,967	$ 0	$ 1,000,593	$ 0	$ 0	$ 0	$ 14,371,766	$ 54,801,120	$ 5,914,865	$ 0	$ 0	$ 17,720,622	29
30		Total O&M and A&G Expense		$ 231,634,663	$ 0	$ 2,470,681	$ 0	$ 0	$ 0	$ 35,487,003	$ 135,315,840	$ 14,605,084	$ 0	$ 0	$ 43,756,056	30

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DISTRIBUTION OF EXPENSES BY FUNCTION - DATA ENTRY AND CLASSIFICATION OF COSTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line	Acct				Storage				Distribution				Customer Accounting			Line
No.	No.	Description	Allocation	Amount	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	
1		Interest on Customer Deposits	Customer	$ 958,434											$ 958,434	1
2		Taxes Other Than Income	Net Plant	58,155,759	$ 0	$ 1,394,562	$ 0	$ 0	$ 0	$ 19,143,727	$ 37,437,336	$ 180,134	$ 0	$ 0	$ 0	2
3		Interest Expense	Rate Base	47,329,818	0	1,134,959	0	0	0	15,580,041	30,468,217	146,601	0	0	0	3
4		ARAM Federal	Rate Base	(15,458,159)	0	(370,683)	0	0	0	(5,088,520)	(9,951,074)	(47,881)	0	0	0	4
5		Regulatory Amortizations	Rate Base	(3,429,275)	0	(82,233)	0	0	0	(1,128,850)	(2,207,570)	(10,622)	0	0	0	5
		Rate Base														
6		Total Direct Net Plant		$ 3,155,975,561	$ 0	$ 77,972,673	$ 0	$ 0	$ 0	$ 1,038,111,423	$ 2,030,123,293	$ 9,768,172	$ 0	$ 0	$ 0	6
7		Total Common Systems Allocable Net Plant		95,625,305	0	0	0	0	0	32,251,341	63,070,493	303,471	0	0	0	7
8		Total Net Plant		$ 3,251,600,867	$ 0	$ 77,972,673	$ 0	$ 0	$ 0	$ 1,070,362,764	$ 2,093,193,786	$ 10,071,643	$ 0	$ 0	$ 0	8
9		Cash Working Capital	Net Plant	$ (10,297,032)	$ 0	$ (246,921)	$ 0	$ 0	$ 0	$ (3,389,579)	$ (6,628,637)	$ (31,894)	$ 0	$ 0	$ 0	9
10		Materials & Supplies	Net Plant	36,813,908	0	882,789	0	0	0	12,118,411	23,698,678	114,029	0	0	0	10
11		Prepayments	Net Plant	7,721,011	0	185,148	0	0	0	2,541,604	4,970,343	23,915	0	0	0	11
12		Other		0	0	0	0	0	0	0	0	0	0	0	0	12
13		Customer Deposits	Customer	(36,862,844)	0	(883,963)	0	0	0	(12,134,520)	(23,730,181)	(114,181)	0	0	0	13
14		Customer Advances	Customer	(41,613,406)	0	(997,880)	0	0	0	(13,698,311)	(26,788,319)	(128,895)	0	0	0	14
15		Deferred Taxes	Net Plant	(594,534,243)	0	(14,256,800)	0	0	0	(195,708,927)	(382,726,981)	(1,841,535)	0	0	0	15
16		Other		0	0	0	0	0	0	0	0	0	0	0	0	16
17		Total Rate Base		$ 2,612,828,261	$ 0	$ 62,655,047	$ 0	$ 0	$ 0	$ 860,091,443	$ 1,681,988,689	$ 8,093,083	$ 0	$ 0	$ 0	17
		Revenue														
18		Net Operating Margin		$ 483,951,321	$ 0	$ 11,605,046	$ 0	$ 0	$ 0	$ 159,307,214	$ 311,540,050	$ 1,499,011	$ 0	$ 0	$ 0	18
19		Special Contract & Optional Margin		5,008,186	0	120,095	0	0	0	1,648,596	3,223,982	15,513	0	0	0	19
20		Late Charges		1,615,145	0	38,731	0	0	0	531,674	1,039,737	5,003	0	0	0	20
21		Service Establishment Charges		7,218,698	0	173,103	0	0	0	2,376,253	4,646,983	22,359	0	0	0	21
22		Reconnect / Reread Charges		224,248	0	5,377	0	0	0	73,818	144,358	695	0	0	0	22
23		Other Revenue - Labor		4,325	0	104	0	0	0	1,424	2,784	13	0	0	0	23
24		Other Revenue - Parts & Material		377	0	9	0	0	0	124	243	1	0	0	0	24
25		Other Revenue - Field Collection Fee		(21)	0	(1)	0	0	0	(7)	(14)	(0)	0	0	0	25
26		Other Revenue - Returned Item Fee		496,902	0	11,916	0	0	0	163,570	319,877	1,539	0	0	0	26
27		Other Revenue - Rental Income & UESC Revenue		113,867	0	2,731	0	0	0	37,483	73,301	353	0	0	0	27
28		Total Revenue		$ 498,633,048	$ 0	$ 11,957,111	$ 0	$ 0	$ 0	$ 164,140,148	$ 320,991,302	$ 1,544,487	$ 0	$ 0	$ 0	28

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DISTRIBUTION OF EXPENSES BY FUNCTION - DATA ENTRY AND CLASSIFICATION OF COSTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Acct No. (a)	Description (b)	Allocation (c)	Amount (d)	Storage Specific (e)	Storage Demand (f)	Storage Customer (g)	Storage Commodity (h)	Distribution Specific (i)	Distribution Demand (j)	Distribution Customer (k)	Distribution Commodity (l)	Customer Accounting Specific (m)	Customer Accounting Demand (n)	Customer Accounting Customer (o)	Line No.
		Operating Deductions														
1		Operations & Maintenance Expenses		$ (137,825,696)	$ 0	$ (1,470,088)	$ 0	$ 0	$ 0	$ (21,115,237)	$ (80,514,719)	$ (8,690,219)	$ 0	$ 0	$ (26,035,434)	1
2		Administrative & General Expenses		(93,808,967)	0	(1,000,593)	0	0	0	(14,371,766)	(54,801,120)	(5,914,865)	0	0	(17,720,622)	2
3		Depreciation Expenses		(112,627,474)	0	(3,497,064)	0	0	0	(28,303,691)	(68,408,938)	(12,417,781)	0	0	0	3
4		Interest on Customer Deposits		(958,434)	0	0	0	0	0	0	0	0	0	0	(958,434)	4
5		Taxes Other Than Income		(58,155,759)	0	(1,394,562)	0	0	0	(19,143,727)	(37,437,336)	(180,134)	0	0	0	5
6		Total Operating Deductions		$ (403,376,330)	$ 0	$ (7,362,307)	$ 0	$ 0	$ 0	$ (82,934,421)	$ (241,162,114)	$ (27,202,999)	$ 0	$ 0	$ (44,714,490)	6
		State Income Tax														
7		Taxable Income before Interest Expense		$ 95,256,717	$ 0	$ 4,594,804	$ 0	$ 0	$ 0	$ 81,205,727	$ 79,829,189	$ (25,658,512)	$ 0	$ 0	$ (44,714,490)	7
8		Interest Expense		47,329,818	0	1,134,959	0	0	0	15,580,041	30,468,217	146,601	0	0	0	8
9		State Taxable Income		$ 47,926,899	$ 0	$ 3,459,845	$ 0	$ 0	$ 0	$ 65,625,686	$ 49,360,972	$ (25,805,114)	$ 0	$ 0	$ (44,714,490)	9
10		State Income Tax	4.90%	$ 2,348,418.07	$ 0	$ 169,532	$ 0	$ 0	$ 0	$ 3,215,659	$ 2,418,688	$ (1,264,451)	$ 0	$ 0	$ (2,191,010)	10
11		Total State Income Tax		$ 2,348,418	$ 0	$ 169,532	$ 0	$ 0	$ 0	$ 3,215,659	$ 2,418,688	$ (1,264,451)	$ 0	$ 0	$ (2,191,010)	11
		Federal Income Tax														
12		Taxable Income before Interest Expense		$ 95,256,717	$ 0	$ 4,594,804	$ 0	$ 0	$ 0	$ 81,205,727	$ 79,829,189	$ (25,658,512)	$ 0	$ 0	$ (44,714,490)	12
13		Interest Expense		47,329,818	0	1,134,959	0	0	0	15,580,041	30,468,217	146,601	0	0	0	13
14		Federal Taxable Income		$ 47,926,899	$ 0	$ 3,459,845	$ 0	$ 0	$ 0	$ 65,625,686	$ 49,360,972	$ (25,805,114)	$ 0	$ 0	$ (44,714,490)	14
15		Federal Income Tax	19.97%	$ 9,571,481	$ 0	$ 690,966	$ 0	$ 0	$ 0	$ 13,106,106	$ 9,857,880	$ (5,153,539)	$ 0	$ 0	$ (8,929,931)	15
16		ARAM Federal		(15,458,159)	0	(370,683)	0	0	0	(5,088,520)	(9,951,074)	(47,881)	0	0	0	16
17		Total Federal Income Tax		$ (5,886,678)	$ 0	$ 320,282	$ 0	$ 0	$ 0	$ 8,017,585	$ (93,195)	$ (5,201,420)	$ 0	$ 0	$ (8,929,931)	17
18		Regulatory Amortization	Net Plant	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	18
19		Net Income		$ 98,794,977	$ 0	$ 4,104,989	$ 0	$ 0	$ 0	$ 69,972,483	$ 77,503,696	$ (19,192,642)	$ 0	$ 0	$ (33,593,549)	19
20		Rate of Return on Rate Base		3.78%	0	6.55%	0	0	0	8.14%	4.61%	-237.15%	0	0	0	20

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line		Allocation		Single-Family Residential		
No.	Description	Factor No.	Total	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	67,779,710		
	Allocation Percent -	1	100.0000%	59.588370%	0.000000%	0.000000%
2	Storage Plant		146,090,839	76,662,934	0	0
	Allocation Percent -	2	100.0000%	52.476209%	0.000000%	0.000000%
3	Throughput		651,995,946			284,164,455
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	43.583776%
4	Customers		1,083,184		1,003,066	
	Allocation Percent -	4	100.0000%	0.000000%	92.603495%	0.000000%
5	Customers With Mains		1,083,184	0	1,003,066	0
	Allocation Percent -	5	100.0000%	0.000000%	92.603495%	0.000000%
6	Meters for Customers		1,738,291	0	1,003,066	0
	Allocation Percent -	6	100.0000%	0.000000%	57.704158%	0.000000%
7	Service Lines for Customers		1,175,262	0	1,003,066	
	Allocation Percent -	7	100.0000%	0.000000%	85.348314%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841	0	1,003,066	0
	Allocation Percent -	8	100.0000%	0.000000%	93.322254%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	6,595,840	0
	Allocation Percent -	9	100.0000%	0.000000%	88.618673%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		1,003,066	
	Allocation Percent -	11	100.0000%	0.000000%	92.603495%	0.000000%
12	Late Fees		1,615,145	0	1,290,032	0
	Allocation Percent -	12	100.0000%	0.000000%	79.870947%	0.000000%
13	Return Item Fees		496,902	0	449,554	0
	Allocation Percent -	13	100.0000%	0.000000%	90.471361%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144			
	Allocation Percent -	15	100.0000%	0.000000%	0.000000%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	1,003,066	0
	Allocation Percent -	16	100.0000%	0.000000%	92.603495%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	589,772,216	1,639,003,369	4,058,981
	Allocation Percent -	1.1	100.0000%	20.097241%	55.851133%	0.138315%
18	Distribution Mains (Account 376)		1,907,528,579	568,332,591	883,219,063	0
	Allocation Percent -	2.2	100.0000%	29.794185%	46.301747%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	548,898,688	0
	Allocation Percent -	3.3	100.0000%	0.000000%	85.348314%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	568,332,591	1,432,117,751	0
	Allocation Percent -	4.4	100.0000%	22.281818%	56.147029%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	3,548,004	21,620,861	294,436
	Allocation Percent -	5.5	100.0000%	9.102502%	55.468919%	0.755383%
22	Allocable Distribution Maintenance Expenses		43,155,439	7,977,317	25,412,237	0
	Allocation Percent -	6.6	100.0000%	18.485079%	58.885364%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	206,220,445	128,793,685	0
	Allocation Percent -	Net Op Margin	100.0000%	42.611816%	26.612942%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	21,210,658	0
	Allocation Percent -	10.1	100.0000%	0.000000%	89.557536%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	15,049,267	85,297,667	1,066,641
	Allocation Percent -	11.2	100.0000%	10.919057%	61.888073%	0.773906%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor No.	Total	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	1,144,262		
	Allocation Percent -	1	100.0000%	1.005975%	0.000000%	0.000000%
2	Storage Plant		146,090,839	1,451,530	0	0
	Allocation Percent -	2	100.0000%	0.993580%	0.000000%	0.000000%
3	Throughput		651,995,946			6,458,245
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	0.990535%
4	Customers		1,083,184		39,135	
	Allocation Percent -	4	100.0000%	0.000000%	3.612952%	0.000000%
5	Customers With Mains		1,083,184	0	39,135	0
	Allocation Percent -	5	100.0000%	0.000000%	3.612952%	0.000000%
6	Meters for Customers		1,738,291	0	39,135	0
	Allocation Percent -	6	100.0000%	0.000000%	2.251345%	0.000000%
7	Service Lines for Customers		1,175,262		51,997	
	Allocation Percent -	7	100.0000%	0.000000%	4.424333%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841	0	39,135	0
	Allocation Percent -	8	100.0000%	0.000000%	3.640995%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	607,221	0
	Allocation Percent -	9	100.0000%	0.000000%	8.158342%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		39,135	
	Allocation Percent -	11	100.0000%	0.000000%	3.612952%	0.000000%
12	Late Fees		1,615,145	0	85,387	0
	Allocation Percent -	12	100.0000%	0.000000%	5.286648%	0.000000%
13	Return Item Fees		496,902	0	36,400	0
	Allocation Percent -	13	100.0000%	0.000000%	7.325388%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144			
	Allocation Percent -	15	100.0000%	0.000000%	0.000000%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	39,135	0
	Allocation Percent -	16	100.0000%	0.000000%	3.612952%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	9,956,577	70,984,866	92,249
	Allocation Percent -	1.1	100.0000%	0.339283%	2.418900%	0.003144%
18	Distribution Mains (Account 376)		1,907,528,579	9,594,632	34,459,050	0
	Allocation Percent -	2.2	100.0000%	0.502988%	1.806476%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	28,454,113	0
	Allocation Percent -	3.3	100.0000%	0.000000%	4.424333%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	9,594,632	62,913,163	0
	Allocation Percent -	4.4	100.0000%	0.376163%	2.466548%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	59,898	878,242	6,692
	Allocation Percent -	5.5	100.0000%	0.153669%	2.253153%	0.017168%
22	Allocable Distribution Maintenance Expenses		43,155,439	134,674	1,132,515	0
	Allocation Percent -	6.6	100.0000%	0.312066%	2.624271%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	4,863,769	4,555,305	0
	Allocation Percent -	Net Op Margin	100.0000%	1.005012%	0.941273%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	827,540	0
	Allocation Percent -	10.1	100.0000%	0.000000%	3.494113%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	255,646	3,534,331	24,242
	Allocation Percent -	11.2	100.0000%	0.185485%	2.564348%	0.017589%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor No.	Total	Master-Metered Mobile Home Park Demand	Master-Metered Mobile Home Park Customer	Master-Metered Mobile Home Park Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	301,401		
	Allocation Percent -	1	100.0000%	0.264976%	0.000000%	0.000000%
2	Storage Plant		146,090,839	339,929	0	0
	Allocation Percent -	2	100.0000%	0.232683%	0.000000%	0.000000%
3	Throughput		651,995,946			1,395,734
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	0.214071%
4	Customers		1,083,184		104	
	Allocation Percent -	4	100.0000%	0.000000%	0.009601%	0.000000%
5	Customers With Mains		1,083,184	0	104	0
	Allocation Percent -	5	100.0000%	0.000000%	0.009601%	0.000000%
6	Meters for Customers		1,738,291	0	806	0
	Allocation Percent -	6	100.0000%	0.000000%	0.046339%	0.000000%
7	Service Lines for Customers		1,175,262		76	
	Allocation Percent -	7	100.0000%	0.000000%	0.006449%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841		104	
	Allocation Percent -	8	100.0000%	0.000000%	0.009676%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	900	0
	Allocation Percent -	9	100.0000%	0.000000%	0.012092%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		104	
	Allocation Percent -	11	100.0000%	0.000000%	0.009601%	0.000000%
12	Late Fees		1,615,145	0	383	0
	Allocation Percent -	12	100.0000%	0.000000%	0.023688%	0.000000%
13	Return Item Fees		496,902	0	14	0
	Allocation Percent -	13	100.0000%	0.000000%	0.002817%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144			
	Allocation Percent -	15	100.0000%	0.000000%	0.000000%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	104	0
	Allocation Percent -	16	100.0000%	0.000000%	0.009601%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	2,622,583	277,894	19,937
	Allocation Percent -	1.1	100.0000%	0.089368%	0.009470%	0.000679%
18	Distribution Mains (Account 376)		1,907,528,579	2,527,246	91,574	0
	Allocation Percent -	2.2	100.0000%	0.132488%	0.004801%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	41,474	0
	Allocation Percent -	3.3	100.0000%	0.000000%	0.006449%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	2,527,246	133,048	0
	Allocation Percent -	4.4	100.0000%	0.099082%	0.005216%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	15,777	11,538	1,446
	Allocation Percent -	5.5	100.0000%	0.040477%	0.029601%	0.003710%
22	Allocable Distribution Maintenance Expenses		43,155,439	35,473	3,735	0
	Allocation Percent -	6.6	100.0000%	0.082199%	0.008655%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	672,479	82,368	0
	Allocation Percent -	Net Op Margin	100.0000%	0.138956%	0.017020%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	2,199	0
	Allocation Percent -	10.1	100.0000%	0.000000%	0.009286%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	66,911	25,006	5,239
	Allocation Percent -	11.2	100.0000%	0.048547%	0.018143%	0.003801%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor No.	Total	Small General Demand	Small General Customer	Small General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	1,254,914		
	Allocation Percent -	1	100.0000%	1.103255%	0.000000%	0.000000%
2	Storage Plant		146,090,839	1,373,161	0	0
	Allocation Percent -	2	100.0000%	0.939936%	0.000000%	0.000000%
3	Throughput		651,995,946			4,374,101
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	0.670879%
4	Customers		1,083,184		17,690	
	Allocation Percent -	4	100.0000%	0.000000%	1.633118%	0.000000%
5	Customers With Mains		1,083,184	0	17,690	0
	Allocation Percent -	5	100.0000%	0.000000%	1.633118%	0.000000%
6	Meters for Customers		1,738,291	0	17,690	0
	Allocation Percent -	6	100.0000%	0.000000%	1.017647%	0.000000%
7	Service Lines for Customers		1,175,262		26,251	
	Allocation Percent -	7	100.0000%	0.000000%	2.233638%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841		17,690	
	Allocation Percent -	8	100.0000%	0.000000%	1.645793%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	105,340	0
	Allocation Percent -	9	100.0000%	0.000000%	1.415300%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		17,690	
	Allocation Percent -	11	100.0000%	0.000000%	1.633118%	0.000000%
12	Late Fees		1,615,145	0	17,255	0
	Allocation Percent -	12	100.0000%	0.000000%	1.068344%	0.000000%
13	Return Item Fees		496,902	0	3,178	0
	Allocation Percent -	13	100.0000%	0.000000%	0.639563%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144		84	
	Allocation Percent -	15	100.0000%	0.000000%	1.367188%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	17,690	0
	Allocation Percent -	16	100.0000%	0.000000%	1.633118%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	10,919,395	33,589,792	62,479
	Allocation Percent -	1.1	100.0000%	0.372092%	1.144615%	0.002129%
18	Distribution Mains (Account 376)		1,907,528,579	10,522,449	15,576,093	0
	Allocation Percent -	2.2	100.0000%	0.551627%	0.816559%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	14,365,148	0
	Allocation Percent -	3.3	100.0000%	0.000000%	2.233638%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	10,522,449	29,941,241	0
	Allocation Percent -	4.4	100.0000%	0.412539%	1.173864%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	65,690	404,392	4,532
	Allocation Percent -	5.5	100.0000%	0.168529%	1.037478%	0.011627%
22	Allocable Distribution Maintenance Expenses		43,155,439	147,697	542,044	0
	Allocation Percent -	6.6	100.0000%	0.342244%	1.256026%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	3,480,428	5,837,590	0
	Allocation Percent -	Net Op Margin	100.0000%	0.719169%	1.206235%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	384,713	0
	Allocation Percent -	10.1	100.0000%	0.000000%	1.624371%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	278,166	1,653,202	16,419
	Allocation Percent -	11.2	100.0000%	0.201824%	1.199488%	0.011913%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor No.	Total	Medium General Demand	Medium General Customer	Medium General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	7,093,545		
	Allocation Percent -	1	100.0000%	6.236273%	0.000000%	0.000000%
2	Storage Plant		146,090,839	9,624,301	0	0
	Allocation Percent -	2	100.0000%	6.587888%	0.000000%	0.000000%
3	Throughput		651,995,946			46,031,602
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	7.060106%
4	Customers		1,083,184		14,847	
	Allocation Percent -	4	100.0000%	0.000000%	1.370643%	0.000000%
5	Customers With Mains		1,083,184	0	14,847	0
	Allocation Percent -	5	100.0000%	0.000000%	1.370643%	0.000000%
6	Meters for Customers		1,738,291	0	358,203	0
	Allocation Percent -	6	100.0000%	0.000000%	20.606641%	0.000000%
7	Service Lines for Customers		1,175,262		73,461	
	Allocation Percent -	7	100.0000%	0.000000%	6.250586%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841		14,847	
	Allocation Percent -	8	100.0000%	0.000000%	1.381281%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	94,945	0
	Allocation Percent -	9	100.0000%	0.000000%	1.275637%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		14,847	
	Allocation Percent -	11	100.0000%	0.000000%	1.370643%	0.000000%
12	Late Fees		1,615,145	0	65,382	0
	Allocation Percent -	12	100.0000%	0.000000%	4.048087%	0.000000%
13	Return Item Fees		496,902	0	5,460	0
	Allocation Percent -	13	100.0000%	0.000000%	1.098808%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144		1,116	
	Allocation Percent -	15	100.0000%	0.000000%	18.164063%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	14,847	0
	Allocation Percent -	16	100.0000%	0.000000%	1.370643%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	61,723,129	116,730,814	657,511
	Allocation Percent -	1.1	100.0000%	2.103294%	3.977752%	0.022406%
18	Distribution Mains (Account 376)		1,907,528,579	59,479,346	13,072,703	0
	Allocation Percent -	2.2	100.0000%	3.118137%	0.685321%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	40,199,254	0
	Allocation Percent -	3.3	100.0000%	0.000000%	6.250586%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	59,479,346	53,271,958	0
	Allocation Percent -	4.4	100.0000%	2.331923%	2.088559%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	371,319	5,065,475	47,695
	Allocation Percent -	5.5	100.0000%	0.952630%	12.995617%	0.122364%
22	Allocable Distribution Maintenance Expenses		43,155,439	834,873	1,708,826	0
	Allocation Percent -	6.6	100.0000%	1.934572%	3.959700%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	18,745,450	7,749,917	0
	Allocation Percent -	Net Op Margin	100.0000%	3.873416%	1.601384%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	455,445	0
	Allocation Percent -	10.1	100.0000%	0.000000%	1.923020%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	1,591,106	10,488,462	172,784
	Allocation Percent -	11.2	100.0000%	1.154433%	7.609947%	0.125364%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor No.	Total	Large-1 General Demand	Large-1 General Customer	Large-1 General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	15,054,030		
	Allocation Percent -	1	100.0000%	13.234714%	0.000000%	0.000000%
2	Storage Plant		146,090,839	21,157,916	0	0
	Allocation Percent -	2	100.0000%	14.482712%	0.000000%	0.000000%
3	Throughput		651,995,946			109,317,775
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	16.766634%
4	Customers		1,083,184		7,072	
	Allocation Percent -	4	100.0000%	0.000000%	0.652898%	0.000000%
5	Customers With Mains		1,083,184	0	7,072	0
	Allocation Percent -	5	100.0000%	0.000000%	0.652898%	0.000000%
6	Meters for Customers		1,738,291	0	186,440	0
	Allocation Percent -	6	100.0000%	0.000000%	10.725489%	0.000000%
7	Service Lines for Customers		1,175,262		10,358	
	Allocation Percent -	7	100.0000%	0.000000%	0.881310%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841			
	Allocation Percent -	8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	33,780	0
	Allocation Percent -	9	100.0000%	0.000000%	0.453853%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		7,072	
	Allocation Percent -	11	100.0000%	0.000000%	0.652898%	0.000000%
12	Late Fees		1,615,145	0	87,311	0
	Allocation Percent -	12	100.0000%	0.000000%	5.405756%	0.000000%
13	Return Item Fees		496,902	0	2,058	0
	Allocation Percent -	13	100.0000%	0.000000%	0.414166%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144		2,028	
	Allocation Percent -	15	100.0000%	0.000000%	33.007813%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	7,072	0
	Allocation Percent -	16	100.0000%	0.000000%	0.652898%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	130,989,770	44,904,673	1,561,486
	Allocation Percent -	1.1	100.0000%	4.463644%	1.530184%	0.053210%
18	Distribution Mains (Account 376)		1,907,528,579	126,227,980	6,227,106	0
	Allocation Percent -	2.2	100.0000%	6.617357%	0.326449%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	5,667,948	0
	Allocation Percent -	3.3	100.0000%	0.000000%	0.881310%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	126,227,980	11,895,054	0
	Allocation Percent -	4.4	100.0000%	4.948843%	0.466353%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	788,020	2,557,710	113,269
	Allocation Percent -	5.5	100.0000%	2.021687%	6.561876%	0.290595%
22	Allocable Distribution Maintenance Expenses		43,155,439	1,771,780	575,618	0
	Allocation Percent -	6.6	100.0000%	4.105579%	1.333826%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	41,949,603	6,789,200	0
	Allocation Percent -	Net Op Margin	100.0000%	8.668145%	1.402868%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	406,682	0
	Allocation Percent -	10.1	100.0000%	0.000000%	1.717131%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	3,384,045	5,180,747	410,336
	Allocation Percent -	11.2	100.0000%	2.455308%	3.758912%	0.297721%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor No.	Total	Large-2 General Demand	Large-2 General Customer	Large-2 General Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	4,784,636		
	Allocation Percent -	1	100.0000%	4.206401%	0.000000%	0.000000%
2	Storage Plant		146,090,839	6,962,050	0	0
	Allocation Percent -	2	100.0000%	4.765562%	0.000000%	0.000000%
3	Throughput		651,995,946			37,170,444
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	5.701024%
4	Customers		1,083,184		435	
	Allocation Percent -	4	100.0000%	0.000000%	0.040129%	0.000000%
5	Customers With Mains		1,083,184	0	435	0
	Allocation Percent -	5	100.0000%	0.000000%	0.040129%	0.000000%
6	Meters for Customers		1,738,291	0	82,494	0
	Allocation Percent -	6	100.0000%	0.000000%	4.745676%	0.000000%
7	Service Lines for Customers		1,175,262		5,739	
	Allocation Percent -	7	100.0000%	0.000000%	0.488304%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841			
	Allocation Percent -	8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	2,220	0
	Allocation Percent -	9	100.0000%	0.000000%	0.029827%	0.000000%
10	Industrial Meas & Reg		637	0	435	0
	Allocation Percent -	10	100.0000%	0.000000%	68.272251%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		435	
	Allocation Percent -	11	100.0000%	0.000000%	0.040129%	0.000000%
12	Late Fees		1,615,145	0	27,490	0
	Allocation Percent -	12	100.0000%	0.000000%	1.702007%	0.000000%
13	Return Item Fees		496,902	0	140	0
	Allocation Percent -	13	100.0000%	0.000000%	0.028175%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144		924	
	Allocation Percent -	15	100.0000%	0.000000%	15.039063%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	435	0
	Allocation Percent -	16	100.0000%	0.000000%	0.040129%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	41,632,597	18,047,034	530,939
	Allocation Percent -	1.1	100.0000%	1.418684%	0.614976%	0.018092%
18	Distribution Mains (Account 376)		1,907,528,579	40,119,153	382,732	0
	Allocation Percent -	2.2	100.0000%	2.103201%	0.020064%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	3,140,415	0
	Allocation Percent -	3.3	100.0000%	0.000000%	0.488304%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	40,119,153	3,523,148	0
	Allocation Percent -	4.4	100.0000%	1.572895%	0.138127%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	250,457	1,120,009	38,514
	Allocation Percent -	5.5	100.0000%	0.642555%	2.873415%	0.098809%
22	Allocable Distribution Maintenance Expenses		43,155,439	563,127	234,066	0
	Allocation Percent -	6.6	100.0000%	1.304880%	0.542378%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	10,551,202	2,451,520	0
	Allocation Percent -	Net Op Margin	100.0000%	2.180220%	0.506563%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	126,349	0
	Allocation Percent -	10.1	100.0000%	0.000000%	0.533481%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	1,077,943	2,192,449	139,523
	Allocation Percent -	11.2	100.0000%	0.782106%	1.590740%	0.101232%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor No.	Total	Transportation Eligible General Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	13,465,580		
	Allocation Percent -	1	100.0000%	11.838232%	0.000000%	0.000000%
2	Storage Plant		146,090,839	21,732,251	0	0
	Allocation Percent -	2	100.0000%	14.875848%	0.000000%	0.000000%
3	Throughput		651,995,946			120,707,204
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	18.513490%
4	Customers		1,083,184		202	
	Allocation Percent -	4	100.0000%	0.000000%	0.018649%	0.000000%
5	Customers With Mains		1,083,184	0	202	0
	Allocation Percent -	5	100.0000%	0.000000%	0.018649%	0.000000%
6	Meters for Customers		1,738,291	0	35,041	0
	Allocation Percent -	6	100.0000%	0.000000%	2.015808%	0.000000%
7	Service Lines for Customers		1,175,262		1,476	
	Allocation Percent -	7	100.0000%	0.000000%	0.125596%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841			
	Allocation Percent -	8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	0	0
	Allocation Percent -	9	100.0000%	0.000000%	0.000000%	0.000000%
10	Industrial Meas & Reg		637	0	202	0
	Allocation Percent -	10	100.0000%	0.000000%	31.727749%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		202	
	Allocation Percent -	11	100.0000%	0.000000%	0.018649%	0.000000%
12	Late Fees		1,615,145	0	26,176	0
	Allocation Percent -	12	100.0000%	0.000000%	1.620679%	0.000000%
13	Return Item Fees		496,902	0	14	0
	Allocation Percent -	13	100.0000%	0.000000%	0.002817%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144		1,680	
	Allocation Percent -	15	100.0000%	0.000000%	27.343750%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	202	0
	Allocation Percent -	16	100.0000%	0.000000%	0.018649%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	117,168,175	7,155,405	1,724,171
	Allocation Percent -	1.1	100.0000%	3.992655%	0.243830%	0.058753%
18	Distribution Mains (Account 376)		1,907,528,579	112,908,833	177,865	0
	Allocation Percent -	2.2	100.0000%	5.919116%	0.009324%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	807,741	0
	Allocation Percent -	3.3	100.0000%	0.000000%	0.125596%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	112,908,833	985,606	0
	Allocation Percent -	4.4	100.0000%	4.426658%	0.038641%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	704,871	473,245	125,070
	Allocation Percent -	5.5	100.0000%	1.808365%	1.214123%	0.320871%
22	Allocable Distribution Maintenance Expenses		43,155,439	1,584,828	89,093	0
	Allocation Percent -	6.6	100.0000%	3.672372%	0.206448%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	29,543,216	2,302,800	0
	Allocation Percent -	Net Op Margin	100.0000%	6.104584%	0.475833%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	217,285	0
	Allocation Percent -	10.1	100.0000%	0.000000%	0.917439%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	3,055,217	1,093,427	453,087
	Allocation Percent -	11.2	100.0000%	2.216725%	0.793340%	0.328739%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line		Allocation		Air Conditioning		
No.	Description	Factor No.	Total	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	15,049		
	Allocation Percent -	1	100.0000%	0.013230%	0.000000%	0.000000%
2	Storage Plant		146,090,839	40,837	0	0
	Allocation Percent -	2	100.0000%	0.027953%	0.000000%	0.000000%
3	Throughput		651,995,946			228,512
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	0.035048%
4	Customers		1,083,184		19	
	Allocation Percent -	4	100.0000%	0.000000%	0.001754%	0.000000%
5	Customers With Mains		1,083,184	0	19	0
	Allocation Percent -	5	100.0000%	0.000000%	0.001754%	0.000000%
6	Meters for Customers		1,738,291	0	19	0
	Allocation Percent -	6	100.0000%	0.000000%	0.001093%	0.000000%
7	Service Lines for Customers		1,175,262		13	
	Allocation Percent -	7	100.0000%	0.000000%	0.001141%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841			
	Allocation Percent -	8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	0	0
	Allocation Percent -	9	100.0000%	0.000000%	0.000000%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		19	
	Allocation Percent -	11	100.0000%	0.000000%	0.001754%	0.000000%
12	Late Fees		1,615,145	0	559	0
	Allocation Percent -	12	100.0000%	0.000000%	0.034632%	0.000000%
13	Return Item Fees		496,902	0	0	0
	Allocation Percent -	13	100.0000%	0.000000%	0.000000%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144		12	
	Allocation Percent -	15	100.0000%	0.000000%	0.195313%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	19	0
	Allocation Percent -	16	100.0000%	0.000000%	0.001754%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	130,946	27,984	3,264
	Allocation Percent -	1.1	100.0000%	0.004462%	0.000954%	0.000111%
18	Distribution Mains (Account 376)		1,907,528,579	126,186	16,730	0
	Allocation Percent -	2.2	100.0000%	0.006615%	0.000877%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	7,335	0
	Allocation Percent -	3.3	100.0000%	0.000000%	0.001141%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	126,186	24,065	0
	Allocation Percent -	4.4	100.0000%	0.004947%	0.000943%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	788	394	237
	Allocation Percent -	5.5	100.0000%	0.002021%	0.001012%	0.000607%
22	Allocable Distribution Maintenance Expenses		43,155,439	1,771	420	0
	Allocation Percent -	6.6	100.0000%	0.004104%	0.000973%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	31,843	9,870	0
	Allocation Percent -	Net Op Margin	100.0000%	0.006580%	0.002039%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	1,923	0
	Allocation Percent -	10.1	100.0000%	0.000000%	0.008121%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	3,581	3,174	858
	Allocation Percent -	11.2	100.0000%	0.002598%	0.002303%	0.000622%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line		Allocation		Street Lighting		
No.	Description	Factor No.	Total	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	1,025		
	Allocation Percent -	1	100.0000%	0.000901%	0.000000%	0.000000%
2	Storage Plant		146,090,839	1,942	0	0
	Allocation Percent -	2	100.0000%	0.001329%	0.000000%	0.000000%
3	Throughput		651,995,946			11,108
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	0.001704%
4	Customers		1,083,184		60	
	Allocation Percent -	4	100.0000%	0.000000%	0.005539%	0.000000%
5	Customers With Mains		1,083,184	0	60	0
	Allocation Percent -	5	100.0000%	0.000000%	0.005539%	0.000000%
6	Meters for Customers		1,738,291	0	0	0
	Allocation Percent -	6	100.0000%	0.000000%	0.000000%	0.000000%
7	Service Lines for Customers		1,175,262		43	
	Allocation Percent -	7	100.0000%	0.000000%	0.003669%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841			
	Allocation Percent -	8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	120	0
	Allocation Percent -	9	100.0000%	0.000000%	0.001612%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		60	
	Allocation Percent -	11	100.0000%	0.000000%	0.005539%	0.000000%
12	Late Fees		1,615,145	0	264	0
	Allocation Percent -	12	100.0000%	0.000000%	0.016368%	0.000000%
13	Return Item Fees		496,902	0	0	0
	Allocation Percent -	13	100.0000%	0.000000%	0.000000%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144			
	Allocation Percent -	15	100.0000%	0.000000%	0.000000%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	60	0
	Allocation Percent -	16	100.0000%	0.000000%	0.005539%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	8,919	78,247	159
	Allocation Percent -	1.1	100.0000%	0.000304%	0.002666%	0.000005%
18	Distribution Mains (Account 376)		1,907,528,579	8,595	52,831	0
	Allocation Percent -	2.2	100.0000%	0.000451%	0.002770%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	23,594	0
	Allocation Percent -	3.3	100.0000%	0.000000%	0.003669%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	8,595	76,425	0
	Allocation Percent -	4.4	100.0000%	0.000337%	0.002996%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	54	446	12
	Allocation Percent -	5.5	100.0000%	0.000138%	0.001145%	0.000030%
22	Allocable Distribution Maintenance Expenses		43,155,439	121	1,214	0
	Allocation Percent -	6.6	100.0000%	0.000280%	0.002814%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	8,165	0	0
	Allocation Percent -	Net Op Margin	100.0000%	0.001687%	0.000000%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	1,269	0
	Allocation Percent -	10.1	100.0000%	0.000000%	0.005357%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	235	3,410	42
	Allocation Percent -	11.2	100.0000%	0.000171%	0.002474%	0.000030%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor No.	Total	Compression on Customer's Premises Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	901,562		
	Allocation Percent -	1	100.0000%	0.792606%	0.000000%	0.000000%
2	Storage Plant		146,090,839	1,779,646	0	0
	Allocation Percent -	2	100.0000%	1.218178%	0.000000%	0.000000%
3	Throughput		651,995,946			10,137,535
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	1.554846%
4	Customers		1,083,184		77	
	Allocation Percent -	4	100.0000%	0.000000%	0.007109%	0.000000%
5	Customers With Mains		1,083,184	0	77	0
	Allocation Percent -	5	100.0000%	0.000000%	0.007109%	0.000000%
6	Meters for Customers		1,738,291	0	6,912	0
	Allocation Percent -	6	100.0000%	0.000000%	0.397660%	0.000000%
7	Service Lines for Customers		1,175,262		2,356	
	Allocation Percent -	7	100.0000%	0.000000%	0.200469%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841			
	Allocation Percent -	8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	240	0
	Allocation Percent -	9	100.0000%	0.000000%	0.003225%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		77	
	Allocation Percent -	11	100.0000%	0.000000%	0.007109%	0.000000%
12	Late Fees		1,615,145	0	1,920	0
	Allocation Percent -	12	100.0000%	0.000000%	0.118859%	0.000000%
13	Return Item Fees		496,902	0	0	0
	Allocation Percent -	13	100.0000%	0.000000%	0.000000%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144		132	
	Allocation Percent -	15	100.0000%	0.000000%	2.148438%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	77	0
	Allocation Percent -	16	100.0000%	0.000000%	0.007109%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	7,844,770	2,575,323	144,804
	Allocation Percent -	1.1	100.0000%	0.267321%	0.087757%	0.004934%
18	Distribution Mains (Account 376)		1,907,528,579	7,559,594	67,800	0
	Allocation Percent -	2.2	100.0000%	0.396303%	0.003554%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	1,289,274	0
	Allocation Percent -	3.3	100.0000%	0.000000%	0.200469%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	7,559,594	1,357,074	0
	Allocation Percent -	4.4	100.0000%	0.296378%	0.053205%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	47,193	99,132	10,504
	Allocation Percent -	5.5	100.0000%	0.121076%	0.254325%	0.026948%
22	Allocable Distribution Maintenance Expenses		43,155,439	106,109	40,678	0
	Allocation Percent -	6.6	100.0000%	0.245877%	0.094258%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	2,223,669	86,564	0
	Allocation Percent -	Net Op Margin	100.0000%	0.459482%	0.017887%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	18,365	0
	Allocation Percent -	10.1	100.0000%	0.000000%	0.077542%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	207,823	223,139	38,052
	Allocation Percent -	11.2	100.0000%	0.150787%	0.161899%	0.027609%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor No.	Total	Electric Generation Demand	Electric Generation Customer	Electric Generation Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	1,197,595		
	Allocation Percent -	1	100.0000%	1.052863%	0.000000%	0.000000%
2	Storage Plant		146,090,839	2,168,653	0	0
	Allocation Percent -	2	100.0000%	1.484455%	0.000000%	0.000000%
3	Throughput		651,995,946			14,405,620
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	2.209465%
4	Customers		1,083,184		25	
	Allocation Percent -	4	100.0000%	0.000000%	0.002308%	0.000000%
5	Customers With Mains		1,083,184	0	25	0
	Allocation Percent -	5	100.0000%	0.000000%	0.002308%	0.000000%
6	Meters for Customers		1,738,291	0	1,881	0
	Allocation Percent -	6	100.0000%	0.000000%	0.108199%	0.000000%
7	Service Lines for Customers		1,175,262		26	
	Allocation Percent -	7	100.0000%	0.000000%	0.002193%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841			
	Allocation Percent -	8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	60	0
	Allocation Percent -	9	100.0000%	0.000000%	0.000806%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		25	
	Allocation Percent -	11	100.0000%	0.000000%	0.002308%	0.000000%
12	Late Fees		1,615,145	0	856	0
	Allocation Percent -	12	100.0000%	0.000000%	0.053017%	0.000000%
13	Return Item Fees		496,902	0	14	0
	Allocation Percent -	13	100.0000%	0.000000%	0.002817%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144		84	
	Allocation Percent -	15	100.0000%	0.000000%	1.367188%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	25	0
	Allocation Percent -	16	100.0000%	0.000000%	0.002308%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	10,420,644	367,712	205,769
	Allocation Percent -	1.1	100.0000%	0.355097%	0.012530%	0.007012%
18	Distribution Mains (Account 376)		1,907,528,579	10,041,829	22,013	0
	Allocation Percent -	2.2	100.0000%	0.526431%	0.001154%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	14,104	0
	Allocation Percent -	3.3	100.0000%	0.000000%	0.002193%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	10,041,829	36,117	0
	Allocation Percent -	4.4	100.0000%	0.393696%	0.001416%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	62,689	25,335	14,926
	Allocation Percent -	5.5	100.0000%	0.160831%	0.064998%	0.038294%
22	Allocable Distribution Maintenance Expenses		43,155,439	140,951	4,371	0
	Allocation Percent -	6.6	100.0000%	0.326612%	0.010128%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	2,293,806	101,208	0
	Allocation Percent -	Net Op Margin	100.0000%	0.473975%	0.020913%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	11,179	0
	Allocation Percent -	10.1	100.0000%	0.000000%	0.047202%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	274,097	57,626	54,073
	Allocation Percent -	11.2	100.0000%	0.198872%	0.041811%	0.039233%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor No.	Total	Small Essential Agricultural User Demand	Small Essential Agricultural User Customer	Small Essential Agricultural User Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	442,425		
	Allocation Percent -	1	100.0000%	0.388957%	0.000000%	0.000000%
2	Storage Plant		146,090,839	811,727	0	0
	Allocation Percent -	2	100.0000%	0.555632%	0.000000%	0.000000%
3	Throughput		651,995,946			4,286,030
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	0.657371%
4	Customers		1,083,184		73	
	Allocation Percent -	4	100.0000%	0.000000%	0.006724%	0.000000%
5	Customers With Mains		1,083,184	0	73	0
	Allocation Percent -	5	100.0000%	0.000000%	0.006724%	0.000000%
6	Meters for Customers		1,738,291	0	1,062	0
	Allocation Percent -	6	100.0000%	0.000000%	0.061110%	0.000000%
7	Service Lines for Customers		1,175,262		51	
	Allocation Percent -	7	100.0000%	0.000000%	0.004348%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841			
	Allocation Percent -	8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	1,200	0
	Allocation Percent -	9	100.0000%	0.000000%	0.016123%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		73	
	Allocation Percent -	11	100.0000%	0.000000%	0.006724%	0.000000%
12	Late Fees		1,615,145	0	2,012	0
	Allocation Percent -	12	100.0000%	0.000000%	0.124597%	0.000000%
13	Return Item Fees		496,902	0	0	0
	Allocation Percent -	13	100.0000%	0.000000%	0.000000%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144		84	
	Allocation Percent -	15	100.0000%	0.000000%	1.367188%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	73	0
	Allocation Percent -	16	100.0000%	0.000000%	0.006724%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	3,849,677	281,156	61,221
	Allocation Percent -	1.1	100.0000%	0.131183%	0.009581%	0.002086%
18	Distribution Mains (Account 376)		1,907,528,579	3,709,732	64,131	0
	Allocation Percent -	2.2	100.0000%	0.194478%	0.003362%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	27,960	0
	Allocation Percent -	3.3	100.0000%	0.000000%	0.004348%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	3,709,732	92,091	0
	Allocation Percent -	4.4	100.0000%	0.145442%	0.003610%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	23,159	14,730	4,441
	Allocation Percent -	5.5	100.0000%	0.059416%	0.037791%	0.011393%
22	Allocable Distribution Maintenance Expenses		43,155,439	52,071	3,595	0
	Allocation Percent -	6.6	100.0000%	0.120659%	0.008330%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	1,232,448	104,880	0
	Allocation Percent -	Net Op Margin	100.0000%	0.254664%	0.021672%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	12,191	0
	Allocation Percent -	10.1	100.0000%	0.000000%	0.051473%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	101,365	40,813	16,088
	Allocation Percent -	11.2	100.0000%	0.073546%	0.029612%	0.011673%

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Allocation Factor No.	Total	Natural Gas Engine Demand	Natural Gas Engine Customer	Natural Gas Engine Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
	Allocation Factors					
1	Coincident Peak (CP) Monthly Demand		113,746,542	310,808		
	Allocation Percent -	1	100.0000%	0.273246%	0.000000%	0.000000%
2	Storage Plant		146,090,839	1,983,962	0	0
	Allocation Percent -	2	100.0000%	1.358033%	0.000000%	0.000000%
3	Throughput		651,995,946			13,307,582
	Allocation Percent -	3	100.0000%	0.000000%	0.000000%	2.041053%
4	Customers		1,083,184		380	
	Allocation Percent -	4	100.0000%	0.000000%	0.035082%	0.000000%
5	Customers With Mains		1,083,184	0	380	0
	Allocation Percent -	5	100.0000%	0.000000%	0.035082%	0.000000%
6	Meters for Customers		1,738,291	0	5,542	0
	Allocation Percent -	6	100.0000%	0.000000%	0.318834%	0.000000%
7	Service Lines for Customers		1,175,262		348	
	Allocation Percent -	7	100.0000%	0.000000%	0.029651%	0.000000%
8	Residential, MMMHP, Small & Medium		1,074,841			
	Allocation Percent -	8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment & Reconnect Charges		7,442,946	0	1,080	0
	Allocation Percent -	9	100.0000%	0.000000%	0.014510%	0.000000%
10	Industrial Meas & Reg		637	0	0	0
	Allocation Percent -	10	100.0000%	0.000000%	0.000000%	0.000000%
11	Meter Reading (Bills with Meters)		1,083,184		380	
	Allocation Percent -	11	100.0000%	0.000000%	0.035082%	0.000000%
12	Late Fees		1,615,145	0	10,117	0
	Allocation Percent -	12	100.0000%	0.000000%	0.626372%	0.000000%
13	Return Item Fees		496,902	0	70	0
	Allocation Percent -	13	100.0000%	0.000000%	0.014087%	0.000000%
14	Extra		0	0	0	0
	Allocation Percent -	14	0.0000%	0.000000%	0.000000%	0.000000%
15	KAM Direct Allocation		6,144			
	Allocation Percent -	15	100.0000%	0.000000%	0.000000%	0.000000%
16	Customers with Gas Light Count		1,083,184	0	380	0
	Allocation Percent -	16	100.0000%	0.000000%	0.035082%	0.000000%
	Internally Generated Allocation Factors					
17	Net Distribution Plant		2,934,592,871	2,704,437	1,511,714	190,084
	Allocation Percent -	1.1	100.0000%	0.092157%	0.051514%	0.006477%
18	Distribution Mains (Account 376)		1,907,528,579	2,606,124	334,597	0
	Allocation Percent -	2.2	100.0000%	0.136623%	0.017541%	0.000000%
19	Distribution Services (Account 380)		643,127,744	0	190,694	0
	Allocation Percent -	3.3	100.0000%	0.000000%	0.029651%	0.000000%
20	Distribution Mains & Services (Accounts 376, 380)		2,550,656,323	2,606,124	525,292	0
	Allocation Percent -	4.4	100.0000%	0.102175%	0.020594%	0.000000%
21	Allocable Distribution Operating Expenses		38,978,336	16,270	77,075	13,789
	Allocation Percent -	5.5	100.0000%	0.041740%	0.197738%	0.035375%
22	Allocable Distribution Maintenance Expenses		43,155,439	36,580	19,654	0
	Allocation Percent -	6.6	100.0000%	0.084764%	0.045543%	0.000000%
23	Extra		0		0	
	Allocation Percent -	7.7	0.0000%	0.000000%	0.000000%	0.000000%
24	Net Operating Margin w/o SPECC and Optional		483,951,321	2,984,891	285,000	0
	Allocation Percent -	Net Op Margin	100.0000%	0.616775%	0.058890%	0.000000%
25	Customer Accounting Expense (Accounts 902-904)		23,683,834	0	8,035	0
	Allocation Percent -	10.1	100.0000%	0.000000%	0.033928%	0.000000%
26	Total Operations and Maintenance Expense		137,825,696	85,436	154,071	49,951
	Allocation Percent -	11.2	100.0000%	0.061989%	0.111787%	0.036242%

SCHEDULE H

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF REVENUES AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Schedule Number	Revenues: Present Rates [1]	Revenues: Proposed Rates [2]	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Residential Service						
1	Single-Family Residential Gas Service	G-5	$ 437,660,913	$ 478,955,486	$ 41,294,573	9.44%	1
2	Multi-Family Residential Gas Service	G-6	11,229,993	12,609,650	1,379,657	12.29%	2
3	Single-Family Low Income Residential Gas Service	G-10	14,944,168	16,019,054	1,074,886	7.19%	3
4	Multi-Family Low Income Residential Gas Service	G-11	958,898	1,057,270	98,372	10.26%	4
5	Special Residential Gas Service for Air Conditioning	G-15	60,102	76,460	16,358	27.22%	5
6	Master-Metered Mobile Home Park Gas Service	G-20	1,248,923	1,301,500	52,577	4.21%	6
	General Gas Service	G-25					
7	Small		10,996,371	11,834,554	838,183	7.62%	7
8	Medium		41,969,525	46,168,988	4,199,463	10.01%	8
9	Large-1		88,389,330	92,102,551	3,713,221	4.20%	9
10	Large-2		23,775,156	25,097,213	1,322,057	5.56%	10
11	Transportation Eligible		36,009,594	38,401,564	2,391,970	6.64%	11
12	Optional Gas Service	G-30	4,204,166	4,204,166	0	0.00%	12
13	Air Conditioning Gas Service	G-40	122,604	126,002	3,398	2.77%	13
14	Street Lighting Gas Service	G-45	12,097	13,703	1,606	13.28%	14
	Gas Service for Compression on Customer's Premises	G-55					
15	Residential		17,789	18,250	461	2.59%	15
16	Small		14,920	15,348	428	2.87%	16
17	Large		3,550,106	3,763,422	213,316	6.01%	17
18	Electric Generation Gas Service	G-60	3,135,889	3,343,907	208,018	6.63%	18
19	Small Essential Agriculture User Gas Service	G-75	2,309,914	2,390,620	80,706	3.49%	19
20	Natural Gas Engine Gas Service	G-80	5,701,585	5,814,034	112,449	1.97%	20
21	Total Gas Sales		$ 686,312,043	$ 743,313,742	$ 57,001,699	8.31%	21
22	Special Contract Service	B-1	3,832,234	3,832,234	0	0.00%	22
23	Other Operating Revenue		9,673,541	9,673,541	0	0.00%	23
24	Total Arizona Revenue		$ 699,817,817	$ 756,819,517	$ 57,001,699	8.15%	24
25	Total Requirement			$ 756,819,260			25
26	Over/(Under) Requirement			$ 256			26

[1] Schedule H-2, Sheets 1-4, column (l).
[2] Schedule H-2, Sheets 1-4, column (k).

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF MARGIN AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Schedule Number	Margin: Margin at Present Rates [1]	Margin: DCA Adjustment [2]	Margin: Adjusted Revenue at Present Rates [3]	Margin: Cost of Service Adjustment [4]	Margin: Proposed Rates [5]	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Residential Service									
1	Single-Family Residential Gas Service	G-5	$ 324,031,462	$ 16,249,343	$ 340,280,805	$ 41,294,573	$ 381,575,378	$ 41,294,573	12%	1
2	Multi-Family Residential Gas Service	G-6	8,701,444	425,186	9,126,630	1,379,657	10,506,287	1,379,657	15%	2
3	Single-Family Low Income Residential Gas Service	G-10	10,943,522	810,336	11,753,858	1,074,886	12,828,744	1,074,886	9%	3
4	Multi-Family Low Income Residential Gas Service	G-11	717,630	58,476	776,106	98,372	874,478	98,372	13%	4
5	Special Residential Gas Service for Air Conditioning	G-15	39,146	0	39,146	16,358	55,504	16,358	42%	5
6	Master-Metered Mobile Home Park Gas Service	G-20	754,847	0	754,847	52,577	807,424	52,577	7%	6
	General Gas Service	G-25								
7	Small		9,318,018	130,594	9,448,612	838,183	10,286,795	838,183	9%	7
8	Medium		26,495,367	(569,872)	25,925,495	4,199,463	30,124,958	4,199,463	16%	8
9	Large-1		48,738,803	2,199,777	50,938,580	3,713,221	54,651,801	3,713,221	7%	9
10	Large-2		13,002,722	281,476	13,284,198	1,322,057	14,606,255	1,322,057	10%	10
11	Transportation Eligible		31,846,016	0	31,846,016	2,391,970	34,237,986	2,391,970	8%	11
12	Optional Gas Service	G-30	1,175,952	0	1,175,952	0	1,175,952	0	0%	12
13	Air Conditioning Gas Service	G-40	41,713	0	41,713	3,398	45,111	3,398	8%	13
14	Street Lighting Gas Service	G-45	8,165	0	8,165	1,606	9,771	1,606	20%	14
	Gas Service for Compression on Customer's Premises	G-55								
15	Residential		10,056	0	10,056	461	10,517	461	5%	15
16	Small		7,746	0	7,746	428	8,174	428	6%	16
17	Large		2,292,431	0	2,292,431	213,316	2,505,747	213,316	9%	17
18	Electric Generation Gas Service	G-60	2,395,014	0	2,395,014	208,018	2,603,032	208,018	9%	18
19	Small Essential Agriculture User Gas Service	G-75	1,337,328	0	1,337,328	80,706	1,418,034	80,706	6%	19
20	Natural Gas Engine Gas Service	G-80	3,269,891	0	3,269,891	112,449	3,382,340	112,449	3%	20
21	Total Sales and Full Margin Transportation		$ 485,127,273	$ 19,585,316	$ 504,712,589	$ 57,001,699	$ 561,714,288	$ 57,001,699	11%	21
22	Special Contract Service	B-1	3,832,234	0	3,832,234	0	3,832,234	0	0%	22
23	Other Operating Revenue		9,673,541	0	9,673,541	0	9,673,541	0	0%	23
24	Total Arizona Margin		$ 498,633,048	$ 19,585,316	$ 518,218,363	$ 57,001,699	$ 575,220,063	$ 57,001,699	11%	24
25	Total Margin Requirement						$ 575,219,806			25
26	Over/(Under) Requirement						$ 256			26

[1] Schedule H-2, Sheets 5-8.
[2] Adjustment to authorized margin per customer for test period volumes.
[3] Test period margin at authorized margin per customer from 2016 Arizona General Rate Case.
[4] Adjustment to reflect the cost of service.
[5] Schedule H-2, Sheets 1-4.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description (a)	Proposed Schedule Number (b)	Billing Determinants: Number of Bills (c)	Billing Determinants: Sales (Therms) (d)	Basic Service Charge (e)	Delivery Charge [1] (f)	Revenue at Proposed Rates: Basic Service Charge (g)	Revenue at Proposed Rates: Delivery Charge (h)	Revenue at Proposed Rates: Total Margin (i)	Revenue at Proposed Rates: Gas Cost [2] (j)	Revenue at Proposed Rates: Total Revenue (k)	Revenue at Present Rates [3] (l)	Increase / Decrease: Dollars (m)	Increase / Decrease: Percent (n)	Line No.
	Single-Family Residential Gas Service	G-5													
1	Basic Service Charge per Month		11,624,565		$ 10.70		$ 124,382,846		$ 124,382,846		$ 124,382,846	$ 124,382,846	$ 0	0.00%	1
	Commodity Charge per Therm														
2	All Usage			275,092,822		$ 0.93493		$ 257,192,532	257,192,532	$ 97,380,108	354,572,640	313,278,067	41,294,573	13.18%	2
3	Total Single-Family Residential		11,624,565	275,092,822			$ 124,382,846	$ 257,192,532	$ 381,575,378	$ 97,380,108	$ 478,955,486	$ 437,660,913	$ 41,294,573	9.44%	3
	Multi-Family Residential Gas Service	G-6													
4	Basic Service Charge per Month		435,728		$ 9.70		$ 4,226,562		$ 4,226,562		$ 4,226,562	$ 4,226,562	$ 0	0.00%	4
	Commodity Charge per Therm														
5	All Usage			5,941,870		$ 1.05686		$ 6,279,725	6,279,725	$ 2,103,363	8,383,088	7,003,431	1,379,657	19.70%	5
6	Total Multi-Family Residential		435,728	5,941,870			$ 4,226,562	$ 6,279,725	$ 10,506,287	$ 2,103,363	$ 12,609,650	$ 11,229,993	$ 1,379,657	12.29%	6
	Single-Family Low Income Residential Gas Service	G-10													
7	Basic Service Charge		411,472		$ 10.70		$ 4,402,750		$ 4,402,750		$ 4,402,750	$ 4,402,750	$ 0	0.00%	7
	Commodity Charge per Therm														
	Summer (May - October)														
8	All Usage			2,031,601		$ 0.93493		$ 1,899,405	1,899,405	$ 719,166	2,618,571	2,376,268	242,303	10.20%	8
	Winter (November - April)														
9	First 150 Therms			6,642,191		0.93493		6,209,984	6,209,984	2,351,269	8,561,253	7,769,060	792,193	10.20%	9
10	Over 150 Therms			338,640		0.93493		316,605	316,605	119,875	436,480	396,091	40,389	10.20%	10
11	Total Single-Family Low-Income		411,472	9,012,432			$ 4,402,750	$ 8,425,994	$ 12,828,744	$ 3,190,310	$ 16,019,054	$ 14,944,168	$ 1,074,886	7.19%	11
	Multi-Family Low Income Residential Gas Service	G-11													
12	Basic Service Charge per Month		33,891		$ 9.70		$ 328,743		$ 328,743		$ 328,743	$ 328,743	$ 0	0.00%	12
	Commodity Charge per Therm														
	Summer (May - October)														
13	All Usage			159,910		$ 1.05686		$ 169,002	169,002	$ 56,607	225,609	195,146	30,463	15.61%	13
	Winter (November - April)														
14	First 150 Therms			353,524		1.05686		373,625	373,625	125,144	498,769	431,420	67,349	15.61%	14
15	Over 150 Therms			2,941		1.05686		3,108	3,108	1,041	4,149	3,589	560	15.60%	15
16	Total Multi-Family Low-Income		33,891	516,375			$ 328,743	$ 545,735	$ 874,478	$ 182,792	$ 1,057,270	$ 958,898	$ 98,372	10.26%	16
	Special Residential Gas Service for Air Conditioning	G-15													
17	Basic Service Charge per Month		756		$ 10.70		$ 8,089		$ 8,089		$ 8,089	$ 8,089	$ 0	0.00%	17
	Commodity Charge per Therm														
	Summer (May - October)														
18	First 15 Therms			12,253		$ 0.93493		$ 11,456	11,456	$ 4,337	15,793	11,743	4,050	34.49%	18
19	Over 15 Therms			10,162		0.15422		1,567	1,567	3,597	5,164	5,013	151	3.01%	19
	Winter (November - April)														
20	All Usage			36,786		0.93493		34,392	34,392	13,022	47,414	35,257	12,157	34.48%	20
21	Total Special Residential AC		756	59,201			$ 8,089	$ 47,415	$ 55,504	$ 20,956	$ 76,460	$ 60,102	$ 16,358	27.22%	21
22	Total Residential Gas Service		12,506,412	290,622,700			$ 133,348,990	$ 272,491,401	$ 405,840,391	$ 102,877,529	$ 508,717,920	$ 464,854,074	$ 43,863,846	9.44%	22
	Master-Metered Mobile Home Park Gas Service	G-20													
23	Basic Service Charge per Month		1,248		$ 66.00		$ 82,368		$ 82,368		$ 82,368	$ 82,368	$ 0	0.00%	23
	Commodity Charge per Therm All Usage														
24	All Usage			1,395,734		$ 0.51948		$ 725,056	725,056	$ 494,076	1,219,132	1,166,555	52,577	4.51%	24
25	Total MMMHP		1,248	1,395,734			$ 82,368	$ 725,056	$ 807,424	$ 494,076	$ 1,301,500	$ 1,248,923	$ 52,577	4.21%	25

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line		Proposed	Billing Determinants		Revenue at Proposed Rates							Revenue	Increase / Decrease		Line
No.	Description	Schedule Number	Number of Bills	Sales (Therms)	Basic Service Charge	Delivery Charge [1]	Basic Service Charge	Delivery Charge	Total Margin	Gas Cost [2]	Total Revenue	at Present Rates [3]	Dollars	Percent	No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	General Gas Service - Small	G-25(S)													
	Basic Service Charge Per Month														
1	Sales Customers		212,192		$ 27.50		$ 5,835,280		$ 5,835,280		$ 5,835,280	$ 5,835,280	$ 0	0.00%	1
2	Transportation Customers		84		27.50		2,310		2,310		2,310	2,310	0	0.00%	2
	Commodity Charge per Therm All Usage														
3	Sales Customers			4,372,324		$ 1.01717		$ 4,447,397	4,447,397	$ 1,547,759	5,995,156	5,157,330	837,826	16.25%	3
4	Transportation Customers			1,777		1.01717		1,808	1,808	0	1,808	1,451	357	24.63%	4
5	Total Small General		212,276	4,374,101			$ 5,837,590	$ 4,449,205	$ 10,286,795	$ 1,547,759	$ 11,834,554	$ 10,996,371	$ 838,183	7.62%	5
	General Gas Service - Medium	G-25(M)													
	Basic Service Charge Per Month														
6	Sales Customers		177,043		$ 43.50		$ 7,701,371		$ 7,701,371		$ 7,701,371	$ 7,701,371	$ 0	0.00%	6
7	Transportation Customers		1,116		43.50		48,546		48,546		48,546	48,546	0	0.00%	7
	Commodity Charge per Therm All Usage														
8	Sales Customers			45,323,399		$ 0.48608		$ 22,030,798	22,030,798	$ 16,044,030	38,074,828	33,935,930	4,138,898	12.20%	8
9	Transportation Customers			708,203		0.48608		344,243	344,243	0	344,243	283,678	60,565	21.35%	9
10	Total Medium General		178,159	46,031,602			$ 7,749,917	$ 22,375,041	$ 30,124,958	$ 16,044,030	$ 46,168,988	$ 41,969,525	$ 4,199,463	10.01%	10
	General Gas Service - Large-1	G-25(L1)													
	Basic Service Charge Per Month														
11	Sales Customers		82,837		$ 80.00		$ 6,626,960		$ 6,626,960		$ 6,626,960	$ 6,626,960	$ 0	0.00%	11
12	Transportation Customers		2,028		80.00		162,240		162,240		162,240	162,240	0	0.00%	12
	Commodity Charge per Therm All Usage														
13	Sales Customers			105,796,067		$ 0.43783		$ 46,320,692	46,320,692	$ 37,450,750	83,771,442	80,211,269	3,560,173	4.44%	13
14	Transportation Customers			3,521,708		0.43783		1,541,909	1,541,909	0	1,541,909	1,388,861	153,048	11.02%	14
15	Total Large-1 General		84,865	109,317,775			$ 6,789,200	$ 47,862,601	$ 54,651,801	$ 37,450,750	$ 92,102,551	$ 88,389,330	$ 3,713,221	4.20%	15
	General Gas Service - Large-2	G-25(L2)													
	Basic Service Charge Per Month														
16	Sales Customers		4,292		$ 470.00		$ 2,017,240		$ 2,017,240		$ 2,017,240	$ 2,017,240	$ 0	0.00%	16
17	Transportation Customers		924		470.00		434,280		434,280		434,280	434,280	0	0.00%	17
	Commodity Charge per Therm All Usage														
18	Sales Customers			29,636,311		$ 0.32700		$ 9,691,074	9,691,074	$ 10,490,958	20,182,032	19,156,389	1,025,643	5.35%	18
19	Transportation Customers			7,534,133		0.32700		2,463,661	2,463,661	0	2,463,661	2,167,247	296,414	13.68%	19
20	Total Large-2 General		5,216	37,170,444			$ 2,451,520	$ 12,154,735	$ 14,606,255	$ 10,490,958	$ 25,097,213	$ 23,775,156	$ 1,322,057	5.56%	20
	General Gas Service -Transportation Eligible	G-25(TE)													
	Basic Service Charge Per Month														
21	Sales Customers		732		$ 950.00		$ 695,400		$ 695,400		$ 695,400	$ 695,400	$ 0	0.00%	21
22	Transportation Customers		1,692		950.00		1,607,400		1,607,400		1,607,400	1,607,400	0	0.00%	22
	Demand Charge per Month														
23	Sales Customers			3,503,428	0.089287			$ 3,753,727	3,753,727		3,753,727	3,505,936	247,791	7.07%	23
24	Transportation Customers			12,242,544	0.089287			13,117,200	13,117,200		13,117,200	12,251,310	865,890	7.07%	24
	Commodity Charge per Therm (All Usage)														
25	Sales Customers			11,761,852		$ 0.12480		1,467,879	1,467,879	$ 4,163,578	5,631,457	5,506,899	124,558	2.26%	25
26	Transportation Customers			108,945,352		0.12480		13,596,380	13,596,380	0	13,596,380	12,442,649	1,153,731	9.27%	26
27	Total Transportation Eligible General		2,424	120,707,204			$ 2,302,800	$ 31,935,186	$ 34,237,986	$ 4,163,578	$ 38,401,564	$ 36,009,594	$ 2,391,970	6.64%	27
28	Total General Gas Service		482,940	317,601,125			$ 25,131,027	$ 118,776,768	$ 143,907,795	$ 69,697,075	$ 213,604,870	$ 201,139,975	$ 12,464,895	6.20%	28

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Basic Service Charge	Delivery Charge [1]	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Delivery Charge	Revenue at Proposed Rates: Total Margin	Revenue at Proposed Rates: Gas Cost [2]	Revenue at Proposed Rates: Total Revenue	Revenue at Present Rates [3]	Increase / Decrease: Dollars	Increase / Decrease: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Air Conditioning Gas Service	G-40													
	Basic Service Charge														
1	Sales - With Other Service - No BSC		24		$ 0.00		$ 0		$ 0		$ 0	$ 0	$ 0	0.00%	1
2	General Service - Small		72		27.50		1,980		1,980		1,980	1,980	0	0.00%	2
3	General Service - Medium		60		43.50		2,610		2,610		2,610	2,610	0	0.00%	3
4	General Service - Large		48		80.00		3,840		3,840		3,840	3,840	0	0.00%	4
5	Essential Agricultural		12		120.00		1,440		1,440		1,440	1,440	0	0.00%	5
6	Transportation - With Other Service - No BSC		12		0.00										6
	Commodity Charge per Therm All Usage														
7	Sales Customers			228,512		$ 0.15422		$ 35,241	35,241	$ 80,891	116,132	112,734	3,398	3.01%	7
8	Transportation Customers			0		0.15422		0	0	0	0	0	0	0.00%	8
9	Total Air Conditioning		228	228,512			$ 9,870	$ 35,241	$ 45,111	$ 80,891	$ 126,002	$ 122,604	$ 3,398	2.77%	9
	Street Lighting Gas Service	G-45													
	Commodity Charge per Therm of Rated Capacity														
10	All Usage		60	11,108		$ 0.87963		$ 9,771	$ 9,771	$ 3,932	$ 13,703	$ 12,097	$ 1,606	13.28%	10
11	Total Street Lighting		60	11,108			$ 0	$ 9,771	$ 9,771	$ 3,932	$ 13,703	$ 12,097	$ 1,606	13.28%	11
	Gas Service for Compression on Customer's Premises	G-55													
	Basic Service Charge														
12	Small		120		$ 27.50		$ 3,300		$ 3,300		$ 3,300	$ 3,300	$ 0	0.00%	12
13	Large		180		250.00		45,000		45,000		45,000	45,000	0	0.00%	13
14	Residential		492		10.70		5,264		5,264		5,264	5,264	0	0.00%	14
15	Transportation Customers		132		250.00		33,000		33,000		33,000	33,000	0	0.00%	15
	Commodity Charge per Therm All Usage														
	Sales Customers														
16	Small			20,267		$ 0.24048		$ 4,874	4,874	$ 7,174	12,048	11,620	428	3.68%	16
17	Large			3,552,853		0.24048		854,390	854,390	1,257,675	2,112,065	2,036,993	75,072	3.69%	17
18	Residential			21,845		0.24048		5,253	5,253	7,733	12,986	12,525	461	3.68%	18
19	Transportation Customers			6,542,569		0.24048		1,573,357	1,573,357	0	1,573,357	1,435,113	138,244	9.63%	19
20	Total CNG		924	10,137,535			$ 86,564	$ 2,437,874	$ 2,524,438	$ 1,272,582	$ 3,797,020	$ 3,582,815	$ 214,205	5.98%	20
	Electric Generation Gas Service	G-60													
	Basic Service Charge														
1	General Service - Small		84		$ 27.50		$ 2,310		$ 2,310		$ 2,310	$ 2,310	$ 0	0.00%	1
2	General Service - Medium		48		43.50		2,088		2,088		2,088	2,088	0	0.00%	2
3	General Service - Large		48		80.00		3,840		3,840		3,840	3,840	0	0.00%	3
4	General Service - TE		24		950.00		22,800		22,800		22,800	22,800	0	0.00%	4
5	Essential Agricultural		12		120.00		1,440		1,440		1,440	1,440	0	0.00%	5
6	Transportation - General Service - Small		12		27.50		330		330		330	330	0	0.00%	6
7	Transportation - General Service - TE		72		950.00		68,400		68,400		68,400	68,400	0	0.00%	7
	Commodity Charge per Therm All Usage														
8	Sales Customers			2,092,925		$ 0.17367		$ 363,478	363,478	$ 740,875	1,104,353	1,074,131	30,222	2.81%	8
9	Transportation Customers			12,312,695		0.17367		2,138,346	2,138,346	0	2,138,346	1,960,550	177,796	9.07%	9
10	Total Electric Generation		300	14,405,620			$ 101,208	$ 2,501,824	$ 2,603,032	$ 740,875	$ 3,343,907	$ 3,135,889	$ 208,018	6.63%	10
	Small Essential Agriculture User Gas Service	G-75													
	Basic Service Charge Per Month														
11	Sales Customers		790		$ 120.00		$ 94,800		$ 94,800		$ 94,800	$ 94,800	$ 0	0.00%	11
12	Transportation Customers		84		120.00		10,080		10,080		10,080	10,080	0	0.00%	12
	Commodity Charge per Therm All Usage														
13	Sales Customers			2,747,497		$ 0.30638		$ 841,778	841,778	$ 972,586	1,814,364	1,762,629	51,735	2.94%	13
14	Transportation Customers			1,538,533		0.30638		471,376	471,376	0	471,376	442,405	28,971	6.55%	14
15	Total Small Essential Agricultural		874	4,286,030			$ 104,880	$ 1,313,154	$ 1,418,034	$ 972,586	$ 2,390,620	$ 2,309,914	$ 80,706	3.49%	15

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Basic Service Charge	Delivery Charge [1]	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Delivery Charge	Revenue at Proposed Rates: Total Margin	Revenue at Proposed Rates: Gas Cost [2]	Revenue at Proposed Rates: Total Revenue	Revenue at Present Rates [3]	Increase / Decrease: Dollars	Increase / Decrease: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Natural Gas Engine Gas Service	G-80													
	Basic Service Charge														
1	Off-Peak Season (October - March)		2,280		$ 0.00		$ 0		$ 0		$ 0	$ 0	$ 0	0.00%	1
2	Peak Season (April - September)		2,280		125.00		285,000		285,000		285,000	285,000	0	0.00%	2
3	Transportation Customers - Off-Peak		0		0.00		0		0		0	0	0	0.00%	3
4	Transportation Customers - Peak		0		125.00		0		0		0	0	0	0.00%	4
	Commodity Charge per Therm All Usage														
5	Sales Customers			13,307,582		$ 0.23275		$ 3,097,340	3,097,340	$ 2,431,694	5,529,034	5,416,585	112,449	2.08%	5
6	Transportation Customers			0		0.23275		0	0	0	0	0	0	0.00%	6
7	Total Natural Gas Engine		4,560	13,307,582			$ 285,000	$ 3,097,340	$ 3,382,340	$ 2,431,694	$ 5,814,034	$ 5,701,585	$ 112,449	1.97%	7
8	Total Tariff Sales		12,997,546	651,995,946			$ 159,149,907	$ 401,388,429	$ 560,538,336	$ 178,571,240	$ 739,109,576	$ 682,107,877	$ 57,001,699	8.36%	8
9	Optional Gas Service	G-30	24	9,424,242					1,175,952	3,028,214	4,204,166	4,204,166	0	0.00%	9
10	Potential Bypass/Standby Gas Service	B-1	252	35,052,433					3,832,234		3,832,234	3,832,234	0	0.00%	10
11	Other Operating Revenues						9,673,541		9,673,541		9,673,541	9,673,541	0	0.00%	11
12	Total		12,997,822	696,472,621			$ 168,823,448	$ 401,388,429	$ 575,220,063	$ 181,599,454	$ 756,819,517	$ 699,817,817	$ 57,001,699	8.15%	12
13	Total Revenue Requirement								575,219,806						13
14	Over/(Under)								$ 256						14

[1] Calculated rates to recover proposed Margin per Schedule H-1, Sheet 2.
[2] Gas Cost rate effective on January 31, 2019.
[3] Schedule H-2, Sheets 5-8, Including DCA Adjustment.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF REVENUES AT PRESENT RATES BEFORE DCA ADJUSTMENT
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

			Billing Determinants		Present Margin Rates [1]		Margin at Present Rates			Revenue at Present Rates		
Line No.	Description	Proposed Schedule Number	Number of Bills	Sales (Therms)	Basic Service Charge	Delivery Charge	Basic Service Charge	Delivery Charge	Total Margin	Gas Cost [2]	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Single-Family Residential Gas Service	G-5										
1	Basic Service Charge per Month		11,624,565		$ 10.70		$ 124,382,846		$ 124,382,846		$ 124,382,846	1
	Commodity Charge per Therm											
2	All Usage			275,092,822		$ 0.72575		$ 199,648,616	199,648,616	$ 97,380,108	297,028,724	2
3	Total Single-Family Residential		11,624,565	275,092,822			$ 124,382,846	$ 199,648,616	$ 324,031,462	$ 97,380,108	$ 421,411,570	3
	Multi-Family Residential Gas Service	G-6										
4	Basic Service Charge per Month		435,728		$ 9.70		$ 4,226,562		$ 4,226,562		$ 4,226,562	4
	Commodity Charge per Therm											
5	All Usage			5,941,870		$ 0.75311		$ 4,474,882	4,474,882	$ 2,103,363	6,578,245	5
6	Total Multi-Family Residential		435,728	5,941,870			$ 4,226,562	$ 4,474,882	$ 8,701,444	$ 2,103,363	$ 10,804,807	6
	Single-Family Low Income Residential Gas Service	G-10										
7	Basic Service Charge		411,472		$ 10.70		$ 4,402,750		$ 4,402,750		$ 4,402,750	7
	Commodity Charge per Therm											
	Summer (May - October)											
8	All Usage			2,031,601		$ 0.72575		$ 1,474,434	1,474,434	$ 719,166	2,193,600	8
	Winter (November - April)											
9	First 150 Therms			6,642,191		0.72575		4,820,570	4,820,570	2,351,269	7,171,839	9
10	Over 150 Therms			338,640		0.72575		245,768	245,768	119,875	365,643	10
11	Total Single-Family Low-Income		411,472	9,012,432			$ 4,402,750	$ 6,540,772	$ 10,943,522	$ 3,190,310	$ 14,133,832	11
	Multi-Family Low Income Residential Gas Service	G-11										
12	Basic Service Charge per Month		33,891		$ 9.70		$ 328,743		$ 328,743		$ 328,743	12
	Commodity Charge per Therm											
	Summer (May - October)											
13	All Usage			159,910		$ 0.75311		$ 120,430	120,430	$ 56,607	177,037	13
	Winter (November - April)											
14	First 150 Therms			353,524		0.75311		266,242	266,242	125,144	391,386	14
15	Over 150 Therms			2,941		0.75311		2,215	2,215	1,041	3,256	15
16	Total Multi-Family Low-Income		33,891	516,375			$ 328,743	$ 388,887	$ 717,630	$ 182,792	$ 900,422	16
	Special Residential Gas Service for Air Conditioning	G-15										
17	Basic Service Charge per Month		756		$ 10.70		$ 8,089		$ 8,089		$ 8,089	17
	Commodity Charge per Therm											
	Summer (May - October)											
18	First 15 Therms			12,253		$ 0.60445		$ 7,406	7,406	$ 4,337	11,743	18
19	Over 15 Therms			10,162		0.13935		1,416	1,416	3,597	5,013	19
	Winter (November - April)											
20	All Usage			36,786		0.60445		22,235	22,235	13,022	35,257	20
21	Total Special Residential AC		756	59,201			$ 8,089	$ 31,057	$ 39,146	$ 20,956	$ 60,102	21
22	Total Residential Gas Service		12,506,412	290,622,700			$ 133,348,990	$ 211,084,214	$ 344,433,204	$ 102,877,529	$ 447,310,733	22
	Master-Metered Mobile Home Park Gas Service	G-20										
23	Basic Service Charge per Month		1,248		$ 66.00		$ 82,368		$ 82,368		$ 82,368	23
	Commodity Charge per Therm All Usage											
24	All Usage			1,395,734		$ 0.48181		$ 672,479	672,479	$ 494,076	1,166,555	24
25	Total MMMHP		1,248	1,395,734			$ 82,368	$ 672,479	$ 754,847	$ 494,076	$ 1,248,923	25

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF REVENUES AT PRESENT RATES BEFORE DCA ADJUSTMENT
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

			Billing Determinants		Present Margin Rates [1]		Margin at Present Rates			Revenue at Present Rates		
Line No.	Description	Proposed Schedule Number	Number of Bills	Sales (Therms)	Basic Service Charge	Delivery Charge	Basic Service Charge	Delivery Charge	Total Margin	Gas Cost [2]	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	General Gas Service - Small	G-25(S)										
	Basic Service Charge Per Month											
1	Sales Customers		212,192		$ 27.50		$ 5,835,280		$ 5,835,280		$ 5,835,280	1
2	Transportation Customers		84		27.50		2,310		2,310		2,310	2
	Commodity Charge per Therm All Usage											
3	Sales Customers			4,372,324		$ 0.79569		$ 3,479,014	3,479,014	$ 1,547,759	5,026,773	3
4	Transportation Customers			1,777		0.79569		1,414	1,414	0	1,414	4
5	Total Small General		212,276	4,374,101			$ 5,837,590	$ 3,480,428	$ 9,318,018	$ 1,547,759	$ 10,865,777	5
	General Gas Service - Medium	G-25(M)										
	Basic Service Charge Per Month											
6	Sales Customers		177,043		$ 43.50		$ 7,701,371		$ 7,701,371		$ 7,701,371	6
7	Transportation Customers		1,116		43.50		48,546		48,546		48,546	7
	Commodity Charge per Therm All Usage											
8	Sales Customers			45,323,399		$ 0.40723		$ 18,457,048	18,457,048	$ 16,044,030	34,501,078	8
9	Transportation Customers			708,203		0.40723		288,402	288,402	0	288,402	9
10	Total Medium General		178,159	46,031,602			$ 7,749,917	$ 18,745,450	$ 26,495,367	$ 16,044,030	$ 42,539,397	10
	General Gas Service - Large-1	G-25(L1)										
	Basic Service Charge Per Month											
11	Sales Customers		82,837		$ 80.00		$ 6,626,960		$ 6,626,960		$ 6,626,960	11
12	Transportation Customers		2,028		80.00		162,240		162,240		162,240	12
	Commodity Charge per Therm All Usage											
13	Sales Customers			105,796,067		$ 0.38374		$ 40,598,183	40,598,183	$ 37,450,750	78,048,933	13
14	Transportation Customers			3,521,708		0.38374		1,351,420	1,351,420	0	1,351,420	14
15	Total Large-1 General		84,865	109,317,775			$ 6,789,200	$ 41,949,603	$ 48,738,803	$ 37,450,750	$ 86,189,553	15
	General Gas Service - Large-2	G-25(L2)										
	Basic Service Charge Per Month											
16	Sales Customers		4,292		$ 470.00		$ 2,017,240		$ 2,017,240		$ 2,017,240	16
17	Transportation Customers		924		470.00		434,280		434,280		434,280	17
	Commodity Charge per Therm All Usage											
18	Sales Customers			29,636,311		$ 0.28386		$ 8,412,563	8,412,563	$ 10,490,958	18,903,521	18
19	Transportation Customers			7,534,133		0.28386		2,138,639	2,138,639	0	2,138,639	19
20	Total Large-2 General		5,216	37,170,444			$ 2,451,520	$ 10,551,202	$ 13,002,722	$ 10,490,958	$ 23,493,680	20
	General Gas Service - Transportation Eligible	G-25(TE)										
	Basic Service Charge Per Month											
21	Sales Customers		732		$ 950.00		$ 695,400		$ 695,400		$ 695,400	21
22	Transportation Customers		1,692		950.00		1,607,400		1,607,400		1,607,400	22
	Demand Charge per Month											
23	Sales Customers			3,503,428	0.083393			$ 3,505,936	3,505,936		3,505,936	23
24	Transportation Customers			12,242,544	0.083393			12,251,310	12,251,310		12,251,310	24
	Commodity Charge per Therm (All Usage)											
25	Sales Customers			11,761,852		$ 0.11421		$ 1,343,321	1,343,321	$ 4,163,578	5,506,899	25
26	Transportation Customers			108,945,352		0.11421		12,442,649	12,442,649	0	12,442,649	26
27	Total Transportation Eligible General		2,424	120,707,204			$ 2,302,800	$ 29,543,216	$ 31,846,016	$ 4,163,578	$ 36,009,594	27
28	Total General Gas Service		482,940	317,601,125			$ 25,131,027	$ 104,269,899	$ 129,400,926	$ 69,697,075	$ 199,098,001	28

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF REVENUES AT PRESENT RATES BEFORE DCA ADJUSTMENT
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

			Billing Determinants		Present Margin Rates [1]		Margin at Present Rates			Revenue at Present Rates		
Line No.	Description	Proposed Schedule Number	Number of Bills	Sales (Therms)	Basic Service Charge	Delivery Charge	Basic Service Charge	Delivery Charge	Total Margin	Gas Cost [2]	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Air Conditioning Gas Service	G-40										
	Basic Service Charge											
1	Sales - With Other Service - No BSC		24		$ 0.00		$ 0		$ 0		$ 0	1
2	General Service - Small		72		27.50		1,980		1,980		1,980	2
3	General Service - Medium		60		43.50		2,610		2,610		2,610	3
4	General Service - Large		48		80.00		3,840		3,840		3,840	4
5	Essential Agricultural		12		120.00		1,440		1,440		1,440	5
6	Transportation - With Other Service - No BSC		12		0.00		0		0		0	6
	Commodity Charge per Therm All Usage											
7	Sales Customers			228,512		$ 0.13935		$ 31,843	31,843	$ 80,891	112,734	7
8	Transportation Customers			0		0.13935		0	0	0	0	8
9	Total Air Conditioning		228	228,512			$ 9,870	$ 31,843	$ 41,713	$ 80,891	$ 122,604	9
	Street Lighting Gas Service	G-45										
	Commodity Charge per Therm of Rated Capacity											
10	All Usage		60	11,108		$ 0.73507		$ 8,165	$ 8,165	$ 3,932	$ 12,097	10
11	Total Street Lighting		60	11,108			$ 0	$ 8,165	$ 8,165	$ 3,932	$ 12,097	11
	Gas Service for Compression on Customer's Premises	G-55										
	Basic Service Charge											
12	Small		120		$ 27.50		$ 3,300		$ 3,300		$ 3,300	12
13	Large		180		250.00		45,000		45,000		45,000	13
14	Residential		492		10.70		5,264		5,264		5,264	14
15	Transportation Customers		132		250.00		33,000		33,000		33,000	15
	Commodity Charge per Therm All Usage											
	Sales Customers											
16	Small			20,267		$ 0.21935		$ 4,446	4,446	$ 7,174	11,620	16
17	Large			3,552,853		0.21935		779,318	779,318	1,257,675	2,036,993	17
18	Residential			21,845		0.21935		4,792	4,792	7,733	12,525	18
19	Transportation Customers			6,542,569		0.21935		1,435,113	1,435,113	0	1,435,113	19
20	Total CNG		924	10,137,535			$ 86,564	$ 2,223,669	$ 2,310,233	$ 1,272,582	$ 3,582,815	20
	Electric Generation Gas Service	G-60										
	Basic Service Charge											
21	General Service - Small		84		$ 27.50		$ 2,310		$ 2,310		$ 2,310	21
22	General Service - Medium		48		43.50		2,088		2,088		2,088	22
23	General Service - Large		48		80.00		3,840		3,840		3,840	23
24	General Service - TE		24		950.00		22,800		22,800		22,800	24
25	Essential Agricultural		12		120.00		1,440		1,440		1,440	25
26	Transportation - General Service - Small		12		27.50		330		330		330	26
27	Transportation - General Service - TE		72		950.00		68,400		68,400		68,400	27
	Commodity Charge per Therm All Usage											
28	Sales Customers			2,092,925		$ 0.15923		$ 333,256	333,256	$ 740,875	1,074,131	28
29	Transportation Customers			12,312,695		0.15923		1,960,550	1,960,550	0	1,960,550	29
30	Total Electric Generation		300	14,405,620			$ 101,208	$ 2,293,806	$ 2,395,014	$ 740,875	$ 3,135,889	30

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF REVENUES AT PRESENT RATES BEFORE DCA ADJUSTMENT
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

			Billing Determinants		Present Margin Rates [1]		Margin at Present Rates			Revenue at Present Rates		
Line No.	Description	Proposed Schedule Number	Number of Bills	Sales (Therms)	Basic Service Charge	Delivery Charge	Basic Service Charge	Delivery Charge	Total Margin	Gas Cost [2]	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Small Essential Agriculture User Gas Service	G-75										
	Basic Service Charge Per Month											
1	Sales Customers		790		$ 120.00		$ 94,800		$ 94,800		$ 94,800	1
2	Transportation Customers		84		120.00		10,080		10,080		10,080	2
	Commodity Charge per Therm All Usage											
3	Sales Customers			2,747,497		$ 0.28755		$ 790,043	790,043	$ 972,586	1,762,629	3
4	Transportation Customers			1,538,533		0.28755		442,405	442,405	0	442,405	4
5	Total Small Essential Agricultural		874	4,286,030			$ 104,880	$ 1,232,448	$ 1,337,328	$ 972,586	$ 2,309,914	5
	Natural Gas Engine Gas Service	G-80										
	Basic Service Charge											
6	Off-Peak Season (October - March)		2,280		$ 0.00		$ 0		$ 0		$ 0	6
7	Peak Season (April - September)		2,280		125.00		285,000		285,000		285,000	7
8	Transportation Customers - Off-Peak		0		0.00		0		0		0	8
9	Transportation Customers - Peak		0		125.00		0		0		0	9
	Commodity Charge per Therm All Usage											
10	Sales Customers			13,307,582		$ 0.22430		$ 2,984,891	2,984,891	$ 2,431,694	5,416,585	10
11	Transportation Customers			0		0.22430		0	0	0	0	11
12	Total Natural Gas Engine		4,560	13,307,582			$ 285,000	$ 2,984,891	$ 3,269,891	$ 2,431,694	$ 5,701,585	12
13	Total Tariff Sales		12,997,546	651,995,946			$ 159,149,907	$ 324,801,414	$ 483,951,321	$ 178,571,240	$ 662,522,561	13
14	Optional Gas Service	G-30	24	9,424,242					1,175,952	3,028,214	4,204,166	14
15	Potential Bypass/Standby Gas Service	B-1	252	35,052,433					3,832,234		3,832,234	15
16	Other Operating Revenues						9,673,541		9,673,541		9,673,541	16
17	Total		12,997,822	696,472,621			$ 168,823,448	$ 324,801,414	$ 498,633,048	$ 181,599,454	$ 680,232,502	17
18	DCA Adjustment								19,585,316			18
19	Margin at Present Rates with EEP Adjustment								$ 518,218,363			19
20	Total Revenue Requirement								575,219,806			20
21	Deficiency								$ (57,001,443)			21

[1] Present Margin rates effective April 1, 2017.
[2] Gas Cost rate effective on January 31, 2019.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
MARGIN ALLOCATION SPREAD TO CUSTOMER CLASSES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

						General Gas Service													
Line No.	Description	Total	Single-Family Residential	Multi-Family Residential	MMMHP	Small	Medium	Large-1	Large-2	Transportation Eligible	Air Conditioning	Street Lighting	CNG	Electric Generation	Small Essential Agriculture	Natural Gas Engines	Optional & Bypass Transp.	Other Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	
1	Margin at Requested System Rate of Return [1]	$ 575,219,806	$ 416,815,200	$ 14,534,365	$ 517,007	$ 8,242,647	$ 41,294,681	$ 36,514,096	$ 12,999,217	$ 23,520,245	$ 33,410	$ 15,792	$ 2,106,696	$ 2,045,128	$ 793,514	$ 1,106,081	$ 5,008,186	$ 9,673,541	1
2	Margin at Present Rates [2]	$ 518,218,363	$ 352,073,809	$ 9,902,736	$ 754,847	$ 9,448,612	$ 25,925,495	$ 50,938,580	$ 13,284,198	$ 31,846,016	$ 41,713	$ 8,165	$ 2,310,233	$ 2,395,014	$ 1,337,328	$ 3,269,891	$ 5,008,186	$ 9,673,541	2
3	Difference	$ 57,001,443																	3
4	System Average Increase (Excluding B-1, G-30 & Other Revenues)	11.32%																	4
5	% Difference in Present & System ROR Margin Req.		1.1839	1.4677	0.6849	0.8724	1.5928	0.7168	0.9785	0.7386	0.8010	1.9342	0.9119	0.8539	0.5934	0.3383			5
6	Maximum Margin Increase Capped at 2.00 [3]	22.64%	13.40%	16.61%	7.75%	9.88%	18.03%	8.11%	11.08%	8.36%	9.07%	21.90%	10.32%	9.67%	6.72%	3.83%			6
7	Calculated Proposed Increase To Classes Not at System ROR	$ 63,454,131	$ 47,184,387.75	$ 1,645,321.78	$ 58,526	$ 933,086	$ 4,674,648	$ 4,133,475	$ 1,471,540	$ 2,662,543	$ 3,782	$ 1,788	$ 238,483	$ 231,513	$ 89,828	$ 125,211			7
8	Remaining Allocation of Margin Change [4]	$ (6,452,687)	$ (4,798,208)	$ (167,314)	$ (5,952)	$ (94,886)	$ (475,368)	$ (420,335)	$ (149,642)	$ (270,756)	$ (385)	$ (182)	$ (24,251)	$ (23,543)	$ (9,135)	$ (12,733)			8
9	Proposed Margin Requirement	$ 575,219,806	$ 394,459,989	$ 11,380,744	$ 807,422	$ 10,286,811	$ 30,124,775	$ 54,651,719	$ 14,606,096	$ 34,237,803	$ 45,111	$ 9,771	$ 2,524,464	$ 2,602,984	$ 1,418,021	$ 3,382,369	$ 5,008,186	$ 9,673,541	9
10	Proposed Percentage Increase in Margin	11.00%	12.04%	14.93%	6.96%	8.87%	16.20%	7.29%	9.95%	7.51%	8.14%	19.67%	9.27%	8.68%	6.03%	3.44%	0.00%	0.00%	10
11	Rate of Return on Rate Base at Present Rates	3.78%	2.84%	0.17%	12.51%	8.08%	(0.87%)	11.50%	6.01%	11.10%	9.80%	(1.46%)	7.49%	8.42%	15.93%	39.09%	N/A	N/A	11
12	Rate of Return on Rate Base at Proposed Rates	5.98%	5.12%	2.42%	13.84%	9.89%	0.84%	14.05%	8.09%	12.48%	11.27%	0.15%	9.01%	9.81%	17.27%	40.42%	N/A	N/A	12

[1] Class margin required to earn proposed overall system rate of return on rate base. Schedule G-2, Sheet 1.
[2] Schedule G-1, Sheet 1.
[3] Percentage increase in margin capped at 2 times the system average percent increase in margin.
[4] Remaining deficiency spread to classes on percentage of proposed increases on Line 10.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF BILLS AND VOLUMES WITH POST TEST YEAR ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

			Annual Number of Bills			Annual Sales Volumes (Therms)			
Line No.	Description	Schedule Number	Test Period as Adjusted at 01/31/2019	Reclass Adjustment [1]	Post Test Period	12 Months Ended 01/31/2019	Reclass Adjustment [1]	Post Test Period	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
	Residential Service								
1	Single-Family Residential Gas Service	G-5	11,624,565		11,624,565	275,092,822		275,092,822	1
2	Multi-Family Residential Gas Service	G-6	435,728		435,728	5,941,870		5,941,870	2
3	Single-Family Low Income Residential Gas Service	G-10	411,472		411,472	9,012,432		9,012,432	3
4	Multi-Family Low Income Residential Gas Service	G-11	33,891		33,891	516,375		516,375	4
5	Special Residential Gas Service for Air Conditioning	G-15	756		756	59,201		59,201	5
6	Master-Metered Mobile Home Park Gas Service	G-20	1,248		1,248	1,395,734		1,395,734	6
	General Gas Service	G-25							
7	Small		212,276		212,276	4,374,101		4,374,101	7
8	Medium		178,159		178,159	46,031,602		46,031,602	8
9	Large-1		84,865		84,865	109,317,775		109,317,775	9
10	Large-2		5,216		5,216	37,170,444		37,170,444	10
11	Transportation Eligible		2,424		2,424	120,707,204		120,707,204	11
12	Optional Gas Service	G-30	24		24	9,424,242		9,424,242	12
13	Air Conditioning Gas Service	G-40	228		228	228,512		228,512	13
14	Street Lighting Gas Service	G-45	60		60	11,108		11,108	14
	Gas Service for Compression on Customer's Premises	G-55							
15	Residential		492		492	21,845		21,845	15
16	Small		120		120	20,267		20,267	16
17	Large		312		312	10,095,422		10,095,422	17
18	Electric Generation Gas Service	G-60	300		300	14,405,620		14,405,620	18
19	Small Essential Agriculture User Gas Service	G-75	874		874	4,286,030		4,286,030	19
20	Natural Gas Engine Gas Service	G-80	4,560		4,560	13,307,582		13,307,582	20
21	Total Gas Sales		12,997,570	0	12,997,570	661,420,188	0	661,420,188	21
22	Transportation of Customer-Secured Natural Gas	T-1	0		0	0		0	22
23	Potential Bypass/Standby Gas Service	B-1	252		252	35,052,433		35,052,433	23
24	Other Operating Revenue								24
25	Total Arizona		12,997,822	0	12,997,822	696,472,621	0	696,472,621	25

[1] Reclassification Adjustment to move customers and volumes to proper rate schedules at proposed rates.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

			Present Rates							Proposed Rates				
Line No.	Description	Schedule	Delivery Charge [1]	Rate Adjustment [2]	Gas Cost [2]	Test Year DCA Adjustment	Currently Effective Tariff Rate	Description	Schedule	Delivery Charge [3]	Rate Adjustment [4]	Gas Cost [4]	Effective Tariff Rate	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
	Single-Family Residential Gas Service	G-5						Single-Family Residential Gas Service	G-5					
1	Basic Service Charge per Month		$ 10.70				$ 10.70	Basic Service Charge per Month		$ 10.70			$ 10.70	1
	Commodity Charge per Therm							Commodity Charge per Therm						
2	All Usage		$ 0.72575	$ (0.04409)	$ 0.35399	$ 0.04018	$ 1.07583	All Usage		$ 0.93493	$ (0.01239)	$ 0.35399	$ 1.27653	2
	Multi-Family Residential Gas Service	G-6						Multi-Family Residential Gas Service	G-6					
3	Basic Service Charge per Month		$ 9.70				$ 9.70	Basic Service Charge per Month		$ 9.70			$ 9.70	3
	Commodity Charge per Therm							Commodity Charge per Therm						
4	All Usage		$ 0.75311	$ (0.04409)	$ 0.35399	$ 0.04018	$ 1.10319	All Usage		$ 1.05686	$ (0.01239)	$ 0.35399	$ 1.39846	4
	Single-Family Low Income Residential Gas Service	G-10						Single-Family Low Income Residential Gas Service	G-10					
5	Basic Service Charge per Month		$ 7.50				$ 7.50	Basic Service Charge per Month		$ 7.50			$ 7.50	5
	Commodity Charge per Therm							Commodity Charge per Therm						
	Summer (May - October)							Summer (May - October)						
6	All Usage		$ 0.72575	$ (0.06498)	$ 0.35399	$ 0.04018	$ 1.05494	All Usage		$ 0.93493	$ (0.03328)	$ 0.35399	$ 1.25564	6
	Winter (November - April)							Winter (November - April)						
7	First 150 Therms		$ 0.40987	$ (0.06498)	$ 0.35399	$ 0.04018	$ 0.73906	First 150 Therms		$ 0.55488	$ (0.03328)	$ 0.35399	$ 0.87559	7
8	Over 150 Therms		0.72575	$ (0.06498)	$ 0.35399	$ 0.04018	1.05494	Over 150 Therms		$ 0.93493	$ (0.03328)	$ 0.35399	$ 1.25564	8
	Multi-Family Low Income Residential Gas Service	G-11						Multi-Family Low Income Residential Gas Service	G-11					
9	Basic Service Charge per Month		$ 7.50				$ 7.50	Basic Service Charge per Month		$ 7.50			$ 7.50	9
	Commodity Charge per Therm							Commodity Charge per Therm						
	Summer (May - October)							Summer (May - October)						
10	All Usage		$ 0.75311	$ (0.06498)	$ 0.35399	$ 0.04018	$ 1.08230	All Usage		$ 1.05686	$ (0.03328)	$ 0.35399	$ 1.37757	10
	Winter (November - April)							Winter (November - April)						
11	First 150 Therms		$ 0.42902	$ (0.06498)	$ 0.35399	$ 0.04018	0.75821	First 150 Therms		$ 0.54025	$ (0.03328)	$ 0.35399	$ 0.86096	11
12	Over 150 Therms		0.75311	$ (0.06498)	$ 0.35399	$ 0.04018	1.08230	Over 150 Therms		$ 1.05686	$ (0.03328)	$ 0.35399	$ 1.37757	12
	Special Residential Gas Service for Air Conditioning	G-15						Special Residential Gas Service for Air Conditioning	G-15					
13	Basic Service Charge per Month		$ 10.70				$ 10.70	Basic Service Charge per Month		$ 10.70			$ 10.70	13
	Commodity Charge per Therm							Commodity Charge per Therm						
	Summer (May - October)							Summer (May - October)						
14	First 15 Therms		$ 0.60445	$ (0.06166)	$ 0.35399		$ 0.89678	First 15 Therms		$ 0.93493	$ (0.02996)	$ 0.35399	$ 1.25896	14
15	Over 15 Therms		0.13935	$ (0.06166)	$ 0.35399		0.43168	Over 15 Therms		0.15422	$ (0.02996)	$ 0.35399	0.47825	15
	Winter (November - April)							Winter (November - April)						
16	All Usage		$ 0.60445	$ (0.06166)	$ 0.35399		$ 0.89678	All Usage		$ 0.93493	$ (0.02996)	$ 0.35399	$ 1.25896	16
	Master-Metered Mobile Home Park Gas Service	G-20						Master-Metered Mobile Home Park Gas Service	G-20					
17	Basic Service Charge per Month		$ 66.00				$ 66.00	Basic Service Charge per Month		$ 66.00			$ 66.00	17
	Commodity Charge per Therm							Commodity Charge per Therm						
18	All Usage		$ 0.48181	$ (0.04622)	$ 0.35399		$ 0.78958	All Usage		$ 0.51948	$ (0.01452)	$ 0.35399	$ 0.85895	18

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Schedule	Present Rates: Delivery Charge [1]	Present Rates: Rate Adjustment [2]	Present Rates: Gas Cost [2]	Present Rates: Test Year DCA Adjustment	Present Rates: Currently Effective Tariff Rate	Description	Schedule	Proposed Rates: Delivery Charge [3]	Proposed Rates: Rate Adjustment [4]	Proposed Rates: Gas Cost [4]	Proposed Rates: Effective Tariff Rate	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
	General Gas Service	G-25						General Gas Service	G-25					
	Basic Service Charge per Month							Basic Service Charge per Month						
1	Small		$ 27.50				$ 27.50	Small		$ 27.50			$ 27.50	1
2	Medium		43.50				43.50	Medium		43.50			43.50	2
3	Large-1		80.00				80.00	Large-1		80.00			80.00	3
4	Large-2		470.00				470.00	Large-2		470.00			470.00	4
5	Transportation Eligible		950.00				950.00	Transportation Eligible		950.00			950.00	5
	Commodity Charge per Therm							Commodity Charge per Therm						
6	Small, All Usage		$ 0.79569	$ (0.05953)	$ 0.35399	$ 0.04018	$ 1.09015	Small, All Usage		$ 1.01717	$ (0.02783)	$ 0.35399	$ 1.34333	6
7	Medium, All Usage		0.40723	$ (0.05953)	$ 0.35399	$ 0.04018	0.70169	Medium, All Usage		0.48608	$ (0.02783)	$ 0.35399	0.81224	7
8	Large-1, All Usage		0.38374	$ (0.05953)	$ 0.35399	$ 0.04018	0.67820	Large-1, All Usage		0.43783	$ (0.02783)	$ 0.35399	0.76399	8
9	Large-2, All Usage		0.28386	$ (0.05953)	$ 0.35399	$ 0.04018	0.57832	Large-2, All Usage		0.32700	$ (0.02783)	$ 0.35399	0.65316	9
10	Transportation Eligible, All Usage		0.11421	$ (0.06166)	$ 0.35399		0.40654	Transportation Eligible, All Usage		0.12480	$ (0.02996)	$ 0.35399	0.44883	10
	Demand Charge per Month							Demand Charge per Month						
11	Transportation Eligible		$ 0.083393				$ 0.083393	Transportation Eligible		$ 0.089287			$ 0.089287	11
	Optional Gas Service	G-30						Optional Gas Service	G-30					
12	Basic Service Charge per Month			As Specified on A.C.C. Sheet No. 27.				Basic Service Charge per Month			As Specified on A.C.C. Sheet No. 27.			12
	Commodity Charge per Therm							Commodity Charge per Therm						
13	All Usage			As Specified on A.C.C. Sheet No. 28.				All Usage			As Specified on A.C.C. Sheet No. 28.			13
	Air Conditioning Gas Service	G-40						Air Conditioning Gas Service	G-40					
14	Basic Service Charge per Month			As Specified on A.C.C. Sheet No. 32.				Basic Service Charge per Month			As Specified on A.C.C. Sheet No. 32.			14
	Commodity Charge per Therm							Commodity Charge per Therm						
15	All Usage		$ 0.13935	$ (0.06166)	$ 0.35399		$ 0.43168	All Usage		$ 0.15422	$ (0.02996)	$ 0.35399	$ 0.47825	15
	Street Lighting Gas Service	G-45						Street Lighting Gas Service	G-45					
	Commodity Charge per Therm							Commodity Charge per Therm						
	of Rated Capacity							of Rated Capacity						
16	All Usage		$ 0.73507	$ (0.06166)	$ 0.35399		$ 1.02740	All Usage		$ 0.87963	$ (0.02996)	$ 0.35399	$ 1.20366	16
	Compression Gas Service	G-50						Compression Gas Service	G-50					
17	Basic Service Charge per Month			As Specified on A.C.C. Sheet No. 27.				Basic Service Charge per Month			As Specified on A.C.C. Sheet No. 36.			17
	Commodity Charge per Therm							Commodity Charge per Therm						
18	All Usage			As Specified on A.C.C. Sheet No. 28.				All Usage			As Specified on A.C.C. Sheet No. 36.			18

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Schedule	Present Rates: Delivery Charge [1]	Present Rates: Rate Adjustment [2]	Present Rates: Gas Cost [2]	Present Rates: Test Year DCA Adjustment	Present Rates: Currently Effective Tariff Rate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Gas Service for Compression on Customer's Premises	G-55					
	Basic Service Charge per Month						
1	Small		$ 27.50				$ 27.50
2	Large		250.00				250.00
3	Residential		10.70				10.70
	Commodity Charge per Therm						
4	All Usage		$ 0.21935	$ (0.06166)	$ 0.35399		$ 0.51168
	Electric Generation Gas Service	G-60					
5	Basic Service Charge per Month			As Specified on A.C.C. Sheet No. 40.			
	Commodity Charge per Therm						
6	All Usage		$ 0.15923	$ (0.06166)	$ 0.35399		$ 0.45156
	Biogas and Renewable Natural Gas Service	G-65					
7	Basic Service Charge per Month			As Specified on A.C.C. Sheet No. 41A.			
	Commodity Charge per Therm						
8	All Usage			As Specified on A.C.C. Sheet No. 41A.			
	Small Essential Agriculture User Gas Service	G-75					
9	Basic Service Charge per Month		$ 120.00				$ 120.00
	Commodity Charge per Therm						
10	All Usage		$ 0.28755	$ (0.06166)	$ 0.35399		$ 0.57988
	Natural Gas Engine Gas Service	G-80					
	Basic Service Charge per Month						
11	Off-Peak Season (October - March)		$ 0.00				$ 0.00
12	Peak Season (April - September)		125.00				125.00
	Commodity Charge per Therm						
13	All Usage		$ 0.22430	$ (0.01198)	$ 0.18273		$ 0.39505
	Service Establishment Charge						
14	Normal						$ 35.00
15	Expedited						$ 50.00

Description	Schedule	Proposed Rates: Delivery Charge [3]	Proposed Rates: Rate Adjustment [4]	Proposed Rates: Gas Cost [4]	Proposed Rates: Effective Tariff Rate	Line No.
(h)	(i)	(j)	(k)	(l)	(m)	
Gas Service for Compression on Customer's Premis	G-55					
Basic Service Charge per Month						
Small		$ 27.50			$ 27.50	1
Large		250.00			250.00	2
Residential		10.70			10.70	3
Commodity Charge per Therm						
All Usage		$ 0.24048	$ (0.02996)	$ 0.35399	$ 0.56451	4
Electric Generation Gas Service	G-60					
Basic Service Charge per Month			As Specified on A.C.C. Sheet No. 40.			5
Commodity Charge per Therm						
All Usage		$ 0.17367	$ (0.02996)	$ 0.35399	$ 0.49770	6
Biogas and Renewable Natural Gas Service	G-65					
Basic Service Charge per Month			As Specified on A.C.C. Sheet No. 41A.			7
Commodity Charge per Therm						
All Usage			As Specified on A.C.C. Sheet No. 41A.			8
Small Essential Agriculture User Gas Service	G-75					
Basic Service Charge per Month		$ 120.00			$ 120.00	9
Commodity Charge per Therm						
All Usage		$ 0.30638	$ (0.02996)	$ 0.35399	$ 0.63041	10
Natural Gas Engine Gas Service	G-80					
Basic Service Charge per Month						
Off-Peak Season (October - March)		$ 0.00			$ 0.00	11
Peak Season (April - September)		125.00			125.00	12
Commodity Charge per Therm						
All Usage		$ 0.23275	$ 0.01972	$ 0.18273	$ 0.43520	13
Service Establishment Charge						
Normal					$ 35.00	14
Expedited					$ 50.00	15

[1] Present Margin rates effective April 1, 2017.
[2] Present Rate Adjustment and Gas Cost rates effective January 31, 2019.
[3] Calculated rates to recover proposed Margin per Schedule H-1, Sheet 2 of 2.
[4] Rate Adjustment and Gas Cost rates effective January 31, 2019.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
SINGLE-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates [4]	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	8	$ 19.31	$ 20.91	$ 1.60	8.29%	1
2	Average Summer Use [1]	11	22.53	24.74	2.21	9.81%	2
3	125 Percent Average Use	14	25.76	28.57	2.81	10.91%	3
	Winter Season Bills						
4	75 Percent Average Use	28	$ 40.82	$ 46.44	$ 5.62	13.77%	4
5	Average Winter Use [1]	37	50.51	57.93	7.42	14.69%	5
6	125 Percent Average Use	46	60.19	69.42	9.23	15.33%	6
7	Annual Average Use	24	36.16	40.91	4.75	13.14%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 10.70
Commodity Charge	
All Usage	$ 1.07583
Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 10.70
Commodity Charge	
All Usage	$ 1.27653

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.
[4] The DCA adjustment associated with this customer class.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
MULTI-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates [4]	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	7	$ 17.42	$ 19.49	$ 2.07	11.88%	1
2	Average Summer Use [1]	9	19.63	22.29	2.66	13.55%	2
3	125 Percent Average Use	11	21.84	25.08	3.24	14.84%	3
	Winter Season Bills						
4	75 Percent Average Use	14	$ 25.14	$ 29.28	$ 4.14	16.47%	4
5	Average Winter Use [1]	18	29.56	34.87	5.31	17.96%	5
6	125 Percent Average Use	23	35.07	41.86	6.79	19.36%	6
7	Annual Average Use	14	24.74	28.77	4.03	16.29%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 9.70
Commodity Charge	
All Usage	$ 1.10319
Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 9.70
Commodity Charge	
All Usage	$ 1.39846

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.
[4] The DCA adjustment associated with this customer class.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
SINGLE-FAMILY LOW INCOME RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates [4]	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	8	$ 15.94	$ 17.55	$ 1.61	10.10%	1
2	Average Summer Use [1]	10	18.05	20.06	2.01	11.14%	2
3	125 Percent Average Use	13	21.21	23.82	2.61	12.31%	3
	Winter Season Bills						
4	75 Percent Average Use	26	$ 26.72	$ 30.27	$ 3.55	13.29%	4
5	Average Winter Use [1]	34	32.63	37.27	4.64	14.22%	5
6	125 Percent Average Use	43	39.28	45.15	5.87	14.94%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 7.50
Commodity Charge	
Summer (May-October)	
All Usage	$ 1.05494
Winter (November-April)	
First 150 Therms	$ 0.73906
Over 150 Therms	1.05494
Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 7.50
Commodity Charge	
Summer (May-October)	
All Usage	$ 1.25564
Winter (November-April)	
First 150 Therms	$ 0.87559
Over 150 Therms	1.25564

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.
[4] The DCA adjustment associated with this customer class.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
MULTI-FAMILY LOW INCOME RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	At Currently Effective Rates [4]	At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	7	$ 15.08	$ 17.14	$ 2.06	13.66%	1
2	Average Summer Use [1]	9	17.24	19.90	2.66	15.43%	2
3	125 Percent Average Use	11	19.41	22.65	3.24	16.69%	3
	Winter Season Bills						
4	75 Percent Average Use	16	$ 19.63	$ 21.28	$ 1.65	8.41%	4
5	Average Winter Use [1]	21	23.42	25.58	2.16	9.22%	5
6	125 Percent Average Use	26	27.21	29.89	2.68	9.85%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 7.50
Commodity Charge	
Summer (May-October)	
All Usage	$ 1.08230
Winter (November-April)	
First 150 Therms	$ 0.75821
Over 150 Therms	1.08230
Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 7.50
Commodity Charge	
Summer (May-October)	
All Usage	$ 1.37757
Winter (November-April)	
First 150 Therms	$ 0.86096
Over 150 Therms	1.37757

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.
[4] The DCA adjustment associated with this customer class.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
MASTER-METERED MOBILE HOME PARK GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	341	$ 335.25	$ 358.90	$ 23.65	7.05%	1
2	Average Summer Use [1]	454	424.47	455.96	31.49	7.42%	2
3	125 Percent Average Use	568	514.48	553.88	39.40	7.66%	3
	Winter Season Bills						
4	75 Percent Average Use	1,337	$ 1,121.67	$ 1,214.42	$ 92.75	8.27%	4
5	Average Winter Use [1]	1,783	1,473.82	1,597.51	123.69	8.39%	5
6	125 Percent Average Use	2,229	1,825.97	1,980.60	154.63	8.47%	6
7	Annual Average Use	1,118	948.75	1,026.31	77.56	8.17%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 66.00
Commodity Charge	
All Usage	$ 0.78958
Proposed Tariff Rates [3]	
Basic Service Charge	$ 66.00
Commodity Charge	
All Usage	$ 0.85895

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
GENERAL GAS SERVICE - SMALL

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates [4]	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	5	$ 32.95	$ 34.22	$ 1.27	3.85%	1
2	Average Summer Use [1]	7	35.13	36.90	1.77	5.04%	2
3	125 Percent Average Use	9	37.31	39.59	2.28	6.11%	3
	Winter Season Bills						
4	75 Percent Average Use	26	$ 55.84	$ 62.43	$ 6.59	11.80%	4
5	Average Winter Use [1]	34	64.57	73.17	8.60	13.32%	5
6	125 Percent Average Use	43	74.38	85.26	10.88	14.63%	6
7	Annual Average Use	21	50.39	55.71	5.32	10.56%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 27.50
Commodity Charge	
All Usage	$ 1.09015
Proposed Tariff Rates [3]	
Basic Service Charge	$ 27.50
Commodity Charge	
All Usage	$ 1.34333

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.
[4] The DCA adjustment associated with this customer class.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
GENERAL GAS SERVICE - MEDIUM

			Monthly Bill				
Line No.	Description	Monthly Consumption (Therms)	At Currently Effective Rates [4]	At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	134	$ 137.53	$ 152.34	$ 14.81	10.77%	1
2	Average Summer Use [1]	179	169.10	188.89	19.79	11.70%	2
3	125 Percent Average Use	224	200.68	225.44	24.76	12.34%	3
	Winter Season Bills						
4	75 Percent Average Use	249	$ 218.22	$ 245.75	$ 27.53	12.62%	4
5	Average Winter Use [1]	332	276.46	313.16	36.70	13.27%	5
6	125 Percent Average Use	415	334.70	380.58	45.88	13.71%	6
7	Annual Average Use	256	223.13	251.43	28.30	12.68%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 43.50
Commodity Charge	
All Usage	$ 0.70169
Proposed Tariff Rates [3]	
Basic Service Charge	$ 43.50
Commodity Charge	
All Usage	$ 0.81224

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.
[4] The DCA adjustment associated with this customer class.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
GENERAL GAS SERVICE - LARGE-1

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates [4]	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	697	$ 552.71	$ 612.50	$ 59.79	10.82%	1
2	Average Summer Use [1]	929	710.05	789.75	79.70	11.22%	2
3	125 Percent Average Use	1,161	867.39	966.99	99.60	11.48%	3
	Winter Season Bills						
4	75 Percent Average Use	1,218	$ 906.05	$ 1,010.54	$ 104.49	11.53%	4
5	Average Winter Use [1]	1,624	1,181.40	1,320.72	139.32	11.79%	5
6	125 Percent Average Use	2,030	1,456.75	1,630.90	174.15	11.95%	6
7	Annual Average Use	1,277	946.06	1,055.62	109.56	11.58%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 80.00
Commodity Charge	
All Usage	$ 0.67820
Proposed Tariff Rates [3]	
Basic Service Charge	$ 80.00
Commodity Charge	
All Usage	$ 0.76399

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.
[4] The DCA adjustment associated with this customer class.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
GENERAL GAS SERVICE - LARGE-2

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates [4]	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	3,994	$ 2,779.81	$ 3,078.72	$ 298.91	10.75%	1
2	Average Summer Use [1]	5,325	3,549.55	3,948.08	398.53	11.23%	2
3	125 Percent Average Use	6,656	4,319.30	4,817.43	498.13	11.53%	3
	Winter Season Bills						
4	75 Percent Average Use	6,369	$ 4,153.32	$ 4,629.98	$ 476.66	11.48%	4
5	Average Winter Use [1]	8,492	5,381.09	6,016.63	635.54	11.81%	5
6	125 Percent Average Use	10,615	6,608.87	7,403.29	794.42	12.02%	6
7	Annual Average Use	6,905	4,463.30	4,980.07	516.77	11.58%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 470.00
Commodity Charge	
All Usage	$ 0.57832
Proposed Tariff Rates [3]	
Basic Service Charge	$ 470.00
Commodity Charge	
All Usage	$ 0.65316

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.
[4] The DCA adjustment associated with this customer class.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
GAS SERVICE FOR COMPRESSION ON CUSTOMER'S PREMISES - SMALL

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	124	$ 90.95	$ 97.50	$ 6.55	7.20%	1
2	Average Summer Use [1]	165	111.93	120.64	8.71	7.78%	2
3	125 Percent Average Use	206	132.91	143.79	10.88	8.19%	3
	Winter Season Bills						
4	75 Percent Average Use	130	$ 94.02	$ 100.89	$ 6.87	7.31%	4
5	Average Winter Use [1]	173	116.02	125.16	9.14	7.88%	5
6	125 Percent Average Use	216	138.02	149.43	11.41	8.27%	6
7	Annual Average Use	169	113.97	122.90	8.93	7.84%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 27.50
Commodity Charge	
All Usage	$ 0.51168
Proposed Tariff Rates [3]	
Basic Service Charge	$ 27.50
Commodity Charge	
All Usage	$ 0.56451

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
GAS SERVICE FOR COMPRESSION ON CUSTOMER'S PREMISES - LARGE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	15,004	$ 7,927.25	$ 8,719.91	$ 792.66	10.00%	1
2	Average Summer Use [1]	20,005	10,486.16	11,543.02	1,056.86	10.08%	2
3	125 Percent Average Use	25,006	13,045.07	14,366.14	1,321.07	10.13%	3
	Winter Season Bills						
4	75 Percent Average Use	14,604	$ 7,722.57	$ 8,494.10	$ 771.53	9.99%	4
5	Average Winter Use [1]	19,472	10,213.43	11,242.14	1,028.71	10.07%	5
6	125 Percent Average Use	24,340	12,704.29	13,990.17	1,285.88	10.12%	6
7	Annual Average Use	19,738	10,349.54	11,392.30	1,042.76	10.08%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 250.00
Commodity Charge	
All Usage	$ 0.51168
Proposed Tariff Rates [3]	
Basic Service Charge	$ 250.00
Commodity Charge	
All Usage	$ 0.56451

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
GAS SERVICE FOR COMPRESSION ON CUSTOMER'S PREMISES - RESIDENTIAL

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	32	$ 27.07	$ 28.76	$ 1.69	6.24%	1
2	Average Summer Use [1]	42	32.19	34.41	2.22	6.90%	2
3	125 Percent Average Use	53	37.82	40.62	2.80	7.40%	3
	Winter Season Bills						
4	75 Percent Average Use	35	$ 28.61	$ 30.46	$ 1.85	6.47%	4
5	Average Winter Use [1]	46	34.24	36.67	2.43	7.10%	5
6	125 Percent Average Use	58	40.38	43.44	3.06	7.58%	6
7	Annual Average Use	44	33.21	35.54	2.33	7.02%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 10.70
Commodity Charge	
All Usage	$ 0.51168
Proposed Tariff Rates [3]	
Basic Service Charge	$ 10.70
Commodity Charge	
All Usage	$ 0.56451

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
SMALL ESSENTIAL AGRICULTURE USER GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	2,228	$ 1,411.97	$ 1,524.55	$ 112.58	7.97%	1
2	Average Summer Use [1]	2,970	1,842.24	1,992.32	150.08	8.15%	2
3	125 Percent Average Use	3,713	2,273.09	2,460.71	187.62	8.25%	3
	Winter Season Bills						
4	75 Percent Average Use	2,957	$ 1,834.71	$ 1,984.12	$ 149.41	8.14%	4
5	Average Winter Use [1]	3,943	2,406.47	2,605.71	199.24	8.28%	5
6	125 Percent Average Use	4,929	2,978.23	3,227.29	249.06	8.36%	6
7	Annual Average Use	3,478	2,136.82	2,312.57	175.75	8.22%	7

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 120.00
Commodity Charge	
All Usage	$ 0.57988
Proposed Tariff Rates [3]	
Basic Service Charge	$ 120.00
Commodity Charge	
All Usage	$ 0.63041

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
TYPICAL BILL COMPARISON - PROPOSED VS. CURRENTLY EFFECTIVE RATES
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019
NATURAL GAS ENGINE GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Peak Season Bills						
1	75 Percent Average	3,125	$ 1,359.53	$ 1,485.00	$ 125.47	9.23%	1
2	Average	4,166	1,770.78	1,938.04	167.26	9.45%	2
3	125 Percent Average	5,208	2,182.42	2,391.52	209.10	9.58%	3
	Off-Peak Season Bills						
4	75 Percent Average	1,253	$ 495.00	$ 545.31	50.31	10.16%	4
5	Average	1,671	660.13	727.22	67.09	10.16%	5
6	125 Percent Average	2,089	825.26	909.13	83.87	10.16%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	
Peak Season	$ 125.00
Off-Peak Season	0.00
Commodity Charge	
All Usage	$ 0.39505
Proposed Tariff Rates [3]	
Basic Service Charge	
Peak Season	$ 125.00
Off-Peak Season	0.00
Commodity Charge	
All Usage	$ 0.43520

[1] Company Record.
[2] Rates effective on January 31, 2019 including all adjustments.
[3] Schedule H-3, Sheets 1-3. Rate Adjustments and Gas Cost effective January 31, 2019.

SCHEDULE H-6
SHEET 1 OF 2

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
CALCULATION OF MONTHLY MARGIN PER CUSTOMER - EQUAL SPREAD
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description (a)	Jan (b)	Feb (c)	Mar (d)	Apr (e)	May (f)	Jun (g)	Jul (h)	Aug (i)	Sep (j)	Oct (k)	Nov (l)	Dec (m)	Total / Weighed Avg Annual Margin Per Customer (n)	Line No.
	Single-Family Residential Gas Service														
1	Number of Customers	973,721	973,664	970,855	967,922	966,394	965,443	963,873	963,910	964,928	968,330	971,690	973,835	11,624,565	1
2	Current Monthly Margin per Customer (2016 GRC)	$ 56.27	$ 48.76	$ 38.97	$ 27.78	$ 21.52	$ 20.72	$ 18.83	$ 17.87	$ 18.38	$ 19.41	$ 21.74	$ 40.52	$ 351.27	2
3	Current Monthly Margin (2016 GRC)	$ 54,791,281	$ 47,475,857	$ 37,834,219	$ 26,888,873	$ 20,796,799	$ 20,003,979	$ 18,149,729	$ 17,225,072	$ 17,735,377	$ 18,795,285	$ 21,124,541	$ 39,459,794	$ 340,280,805	3
4	Proposed Monthly Margin per Customer (2019 GRC)	$ 59.82	$ 52.31	$ 42.52	$ 31.33	$ 25.07	$ 24.27	$ 22.39	$ 21.43	$ 21.94	$ 22.96	$ 25.29	$ 44.07	$ 393.90	4
5	Margin Increase / (Decrease) [1]	$ 3.55	$ 3.55	$ 3.55	$ 3.55	$ 3.55	$ 3.55	$ 3.56	$ 3.56	$ 3.56	$ 3.55	$ 3.55	$ 3.55	$ 42.63	5
6	Total Monthly Margin (2019 GRC)	$ 58,247,990	$ 50,932,364	$ 41,280,755	$ 30,324,996	$ 24,227,498	$ 23,431,302	$ 21,581,116	$ 20,656,591	$ 21,170,520	$ 22,232,857	$ 24,574,040	$ 42,916,908	$ 381,576,938	6
	Multi-Family Residential Gas Service														
7	Number of Customers	36,601	36,654	36,612	36,465	36,348	36,157	36,011	35,900	35,930	36,066	36,385	36,599	435,728	7
8	Current Monthly Margin per Customer (2016 GRC)	$ 31.70	$ 28.90	$ 24.85	$ 20.72	$ 18.20	$ 17.83	$ 16.49	$ 15.84	$ 16.18	$ 16.58	$ 17.96	$ 25.69	$ 251.35	8
9	Current Monthly Margin (2016 GRC)	$ 1,160,252	$ 1,059,301	$ 909,808	$ 755,555	$ 661,534	$ 644,679	$ 593,821	$ 568,656	$ 581,347	$ 597,974	$ 653,475	$ 940,228	$ 9,126,630	9
10	Proposed Monthly Margin per Customer (2019 GRC)	$ 34.86	$ 32.06	$ 28.01	$ 23.88	$ 21.37	$ 21.00	$ 19.66	$ 19.01	$ 19.35	$ 19.75	$ 21.13	$ 28.85	$ 289.34	10
11	Margin Increase / (Decrease) [1]	$ 3.16	$ 3.16	$ 3.16	$ 3.16	$ 3.17	$ 3.17	$ 3.17	$ 3.17	$ 3.17	$ 3.17	$ 3.17	$ 3.16	$ 37.99	11
12	Total Monthly Margin (2019 GRC)	$ 1,275,911	$ 1,175,127	$ 1,025,502	$ 870,784	$ 776,757	$ 759,297	$ 707,976	$ 682,459	$ 695,246	$ 712,304	$ 768,815	$ 1,055,881	$ 10,506,059	12
	Single-Family Low Income Residential Gas Service														
13	Number of Customers	34,561	34,634	34,523	34,535	34,197	33,835	34,176	34,132	34,127	34,192	34,242	34,318	411,472	13
14	Current Monthly Margin per Customer (2016 GRC)	$ 54.75	$ 48.40	$ 37.58	$ 26.95	$ 20.78	$ 20.00	$ 18.33	$ 17.46	$ 17.79	$ 18.59	$ 21.40	$ 39.98	$ 342.78	14
15	Current Monthly Margin (2016 GRC)	$ 1,892,215	$ 1,676,286	$ 1,297,374	$ 930,718	$ 710,614	$ 676,700	$ 626,446	$ 595,945	$ 607,119	$ 635,629	$ 732,779	$ 1,372,034	$ 11,753,858	15
16	Proposed Monthly Margin per Customer (2019 GRC)	$ 57.36	$ 51.01	$ 40.19	$ 29.56	$ 23.39	$ 22.62	$ 20.95	$ 20.08	$ 20.40	$ 21.20	$ 24.01	$ 42.59	$ 374.13	16
17	Margin Increase / (Decrease) [1]	$ 2.61	$ 2.61	$ 2.61	$ 2.61	$ 2.61	$ 2.62	$ 2.62	$ 2.62	$ 2.61	$ 2.61	$ 2.61	$ 2.61	$ 31.35	17
18	Total Monthly Margin (2019 GRC)	$ 1,982,419	$ 1,766,680	$ 1,387,479	$ 1,020,855	$ 799,868	$ 765,348	$ 715,987	$ 685,371	$ 696,191	$ 724,870	$ 822,150	$ 1,461,604	$ 12,828,822	18
	Multi-Family Low Income Residential Gas Service														
19	Number of Customers	2,850	2,871	2,848	2,832	2,817	2,779	2,814	2,814	2,794	2,812	2,823	2,837	33,891	19
20	Current Monthly Margin per Customer (2016 GRC)	$ 37.15	$ 33.51	$ 27.72	$ 22.21	$ 19.04	$ 18.88	$ 17.31	$ 16.57	$ 16.84	$ 17.19	$ 18.81	$ 28.99	$ 274.80	20
21	Current Monthly Margin (2016 GRC)	$ 105,878	$ 96,207	$ 78,947	$ 62,899	$ 53,636	$ 52,468	$ 48,710	$ 46,628	$ 47,051	$ 48,338	$ 53,101	$ 82,245	$ 776,106	21
22	Proposed Monthly Margin per Customer (2019 GRC)	$ 40.05	$ 36.41	$ 30.62	$ 25.11	$ 21.94	$ 21.78	$ 20.22	$ 19.48	$ 19.75	$ 20.09	$ 21.71	$ 31.89	$ 309.63	22
23	Margin Increase / (Decrease) [1]	$ 2.90	$ 2.90	$ 2.90	$ 2.90	$ 2.90	$ 2.90	$ 2.91	$ 2.91	$ 2.91	$ 2.90	$ 2.90	$ 2.90	$ 34.83	23
24	Total Monthly Margin (2019 GRC)	$ 114,143	$ 104,533	$ 87,206	$ 71,112	$ 61,805	$ 60,527	$ 56,899	$ 54,817	$ 55,182	$ 56,493	$ 61,287	$ 90,472	$ 874,474	24
	Small General Gas Service														
25	Number of Customers - Sales	17,855	18,079	17,907	17,699	17,616	17,518	17,479	17,444	17,449	17,586	17,825	17,735	212,192	25
26	Number of Customers - Transportation	7	7	7	7	7	7	7	7	7	7	7	7	84	
27	Current Monthly Margin per Customer (2016 GRC)	$ 72.34	$ 64.14	$ 53.95	$ 41.08	$ 36.55	$ 36.25	$ 34.67	$ 34.04	$ 34.34	$ 34.83	$ 36.82	$ 53.78	$ 534.13	27
28	Current Monthly Margin (2016 GRC)	$ 1,292,137	$ 1,160,036	$ 966,460	$ 727,362	$ 644,121	$ 635,281	$ 606,240	$ 594,032	$ 599,439	$ 612,764	$ 656,574	$ 954,165	$ 9,448,612	28
29	Proposed Monthly Margin per Customer (2019 GRC)	$ 76.28	$ 68.08	$ 57.90	$ 45.03	$ 40.50	$ 40.20	$ 38.62	$ 37.99	$ 38.29	$ 38.78	$ 40.77	$ 57.73	$ 581.51	29
30	Margin Increase / (Decrease) [1]	$ 3.94	$ 3.94	$ 3.95	$ 3.95	$ 3.95	$ 3.95	$ 3.95	$ 3.95	$ 3.95	$ 3.95	$ 3.95	$ 3.95	$ 47.38	30
31	Total Monthly Margin (2019 GRC)	$ 1,362,513	$ 1,231,295	$ 1,037,221	$ 797,301	$ 713,732	$ 704,505	$ 675,309	$ 662,963	$ 668,390	$ 682,257	$ 727,011	$ 1,024,246	$ 10,286,742	31
	Medium General Gas Service														
32	Number of Customers - Sales	14,923	14,683	14,670	14,677	14,666	14,685	14,694	14,700	14,721	14,782	14,845	14,997	177,043	32
33	Number of Customers - Transportation	93	93	93	93	93	93	93	93	93	93	93	93	1,116	33
34	Current Monthly Margin per Customer (2016 GRC)	$ 221.00	$ 205.57	$ 175.14	$ 146.13	$ 125.94	$ 121.02	$ 107.92	$ 104.32	$ 108.96	$ 115.88	$ 129.82	$ 183.05	$ 1,746.23	34
35	Current Monthly Margin (2016 GRC)	$ 3,318,536	$ 3,037,502	$ 2,585,592	$ 2,158,340	$ 1,858,748	$ 1,788,434	$ 1,595,813	$ 1,543,206	$ 1,614,133	$ 1,723,715	$ 1,939,251	$ 2,762,225	$ 25,925,495	35
36	Proposed Monthly Margin per Customer (2019 GRC)	$ 244.57	$ 229.14	$ 198.71	$ 169.70	$ 149.51	$ 144.59	$ 131.49	$ 127.90	$ 132.53	$ 139.45	$ 153.39	$ 206.62	$ 2,029.08	36
37	Margin Increase / (Decrease) [1]	$ 23.57	$ 23.57	$ 23.57	$ 23.57	$ 23.57	$ 23.57	$ 23.57	$ 23.58	$ 23.57	$ 23.57	$ 23.57	$ 23.57	$ 282.85	37
38	Total Monthly Margin (2019 GRC)	$ 3,672,463	$ 3,385,773	$ 2,933,556	$ 2,506,469	$ 2,206,618	$ 2,136,751	$ 1,944,343	$ 1,892,025	$ 1,963,299	$ 2,074,319	$ 2,291,340	$ 3,117,896	$ 30,124,851	38

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
CALCULATION OF MONTHLY MARGIN PER CUSTOMER - EQUAL SPREAD
FOR THE TWELVE MONTHS ENDED JANUARY 31, 2019

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total / Weighed Avg Annual Margin Per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Large-1 General Gas Service														
39	Number of Customers - Sales	6,911	6,904	6,896	6,893	6,887	6,871	6,893	6,911	6,915	6,914	6,909	6,933	82,837	39
40	Number of Customers - Transportation	169	169	169	169	169	169	169	169	169	169	169	169	2,028	40
41	Current Monthly Margin per Customer (2016 GRC)	$ 896.24	$ 833.11	$ 720.48	$ 636.49	$ 547.06	$ 509.11	$ 433.72	$ 410.53	$ 428.28	$ 470.55	$ 550.20	$ 766.08	$ 7,202.77	41
42	Current Monthly Margin (2016 GRC)	$ 6,345,379	$ 5,892,587	$ 5,090,191	$ 4,494,892	$ 3,860,055	$ 3,584,134	$ 3,062,931	$ 2,906,552	$ 3,033,936	$ 3,332,906	$ 3,894,316	$ 5,440,700	$ 50,938,580	42
43	Proposed Monthly Margin per Customer (2019 GRC)	$ 939.99	$ 876.86	$ 764.23	$ 680.24	$ 590.81	$ 552.87	$ 477.48	$ 454.29	$ 472.04	$ 514.31	$ 593.95	$ 809.83	$ 7,727.82	43
44	Margin Increase / (Decrease) [1]	$ 43.75	$ 43.75	$ 43.75	$ 43.75	$ 43.75	$ 43.76	$ 43.76	$ 43.76	$ 43.76	$ 43.76	$ 43.75	$ 43.75	$ 525.05	44
45	Total Monthly Margin (2019 GRC)	$ 6,655,129	$ 6,202,031	$ 5,399,285	$ 4,803,855	$ 4,168,755	$ 3,892,205	$ 3,371,964	$ 3,216,373	$ 3,343,931	$ 3,642,858	$ 4,203,978	$ 5,751,413	$ 54,651,777	45
	Large-2 General Gas Service														
46	Number of Customers - Sales	357	359	361	359	359	359	359	358	357	355	353	356	4,292	46
47	Number of Customers - Transportation	77	77	77	77	77	77	77	77	77	77	77	77	924	47
48	Current Monthly Margin per Customer (2016 GRC)	$ 3,550.90	$ 3,303.78	$ 3,234.11	$ 2,766.80	$ 2,417.09	$ 2,262.46	$ 1,835.78	$ 1,746.76	$ 1,825.86	$ 2,004.07	$ 2,461.16	$ 3,147.32	$ 30,561.81	48
49	Current Monthly Margin (2016 GRC)	$ 1,541,091	$ 1,440,448	$ 1,416,540	$ 1,206,325	$ 1,053,851	$ 986,433	$ 800,400	$ 759,841	$ 792,423	$ 865,758	$ 1,058,299	$ 1,362,790	$ 13,284,198	49
50	Proposed Monthly Margin per Customer (2019 GRC)	$ 3,804.36	$ 3,557.24	$ 3,487.57	$ 3,020.26	$ 2,670.55	$ 2,515.92	$ 2,089.24	$ 2,000.23	$ 2,079.33	$ 2,257.53	$ 2,714.62	$ 3,400.78	$ 33,603.35	50
51	Margin Increase / (Decrease) [1]	$ 253.46	$ 253.46	$ 253.46	$ 253.46	$ 253.46	$ 253.46	$ 253.46	$ 253.47	$ 253.47	$ 253.46	$ 253.46	$ 253.46	$ 3,041.54	51
52	Total Monthly Margin (2019 GRC)	$ 1,651,092	$ 1,550,957	$ 1,527,556	$ 1,316,833	$ 1,164,360	$ 1,096,941	$ 910,909	$ 870,100	$ 902,429	$ 975,253	$ 1,167,287	$ 1,472,538	$ 14,606,254	52

[1] Annual Margin Per Customer incremental increase spread equally among months. Some months are adjusted to equal proposed class margin revenue.