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

Description — Page No.

I. INTRODUCTION.. 1

II. OVERVIEW OF THE NEED FOR RATE RELIEF.. 2

III. INFRASTRUCTURE PROGRAMS…………………………………………………………...3

IV. PROPOSED TARIFF CHANGES.. 8

Appendix A – Summary of Qualifications of Matthew D. Derr

Exhibit No.__(MDD-1)

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.

IV. PROPOSED TARIFF CHANGES

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

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:	______

Table of Contents

Description	Page No.
I. DEFINITIONS	1
II. PURPOSE	1
III. APPLICABLE RATE SCHEDULES	1
IV. FILING PROCESS	2
V. ACCOUNTING	2
VI. RATE ADJUSTMENT	3
VII. PLAN REVISION PROCESS	3

Exhibit I

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

Table of Contents
Prepared Direct Testimony
of

BYRON C. WILLIAMS

Description — Page No.

I. INTRODUCTION.. 1
II. INCOME TAXES AND THE TCJA 2
III. EXCESS ACCUMULATED DEFERRED INCOME TAXES 3
IV. MODIFIED BUSINESS TAX 6
V. PROPERTY TAX MECHANSIM ……………………………………………………...7

Appendix A – Summary of Qualifications of Byron C. Williams

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

Table of Contents
of
Prepared Direct Testimony
of
KEVIN M. LANG

Description | Page No.

I. INTRODUCTION 1
II. 7000/8000 PIPE REPLACEMENT PROGRAM 2

Appendix A – Summary of Qualifications of Kevin M. Lang

Exhibit No.__(KML-1)

Exhibit No.__(KML-2)

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.

II. 7000/8000 PIPE REPLACEMENT PROGRAM

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

Table of Contents
of
Prepared Direct Testimony
of
JOHN R. OLENICK

Description	Page No.
I. INTRODUCTION……………………………………………………………………….........1
II. HIGH-LEVEL OVERVIEW OF RNG PRODUCTION AND ENVIRONMENTAL BENEFITS…………………………………………………………………………………….2
III. SUMMARY OF THE COMPANY'S PROPOSED RNG PROGRAM………………4
IV. RNG CUSTOMER IMPACT SUMMARY..9

Appendix A – Summary of Qualifications 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

---

[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. SUMMARY OF THE COMPANY'S PROPOSED RNG PROGRAM

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

---

[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

[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

---

[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

Table of Contents
Prepared Direct Testimony
of

CARLA AYALA

Description	Page No.
I. INTRODUCTION	1
II. METHODOLOGY USED TO DEVELOP BILLING DETERMINANTS	2
II. ADJUSTMENTS TO RECORDED NUMBER OF BILLS AND VOLUMES	3

Appendix A – Summary of Qualifications of Carla Ayala

Southwest Gas Corporation
Docket No. G-01551A-19-0055

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.

II. ADJUSTMENTS TO RECORDED NUMBER OF BILLS AND VOLUMES

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

Table of Contents
Prepared Direct Testimony
of
KRISTIEN M. TARY

Description	Page No.

I. INTRODUCTION 1
II. PURPOSE OF A CLASS COST OF SERVICE STUDY (CCOSS) 2
III. DEVELOPMENT OF THE CCOSS 3
IV. RATE DESIGN 6

Appendix A – Summary of Qualifications of Kristien M. Tary

Exhibit No.___(KMT-1)

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

Table of Contents
Prepared Direct Testimony
of
DANE A. WATSON

Description	Page No.
I. INTRODUCTION	1
II. PURPOSE OF DIRECT TESTIMONY	3
III. SOUTHWEST GAS - ARIZONA REMOVAL COST ALLOCATION STUDY	4
IV. CONCLUSION	13

Appendix A – Summary of Qualifications of Dane A. Watson

Exhibit No.___(DAW-1)

Southwest Gas Corporation
Docket No. G-01551A-19-0055

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 4
BACKGROUND 5
PROCESS 7
SPECIFIC ACTIVITY 2014 – PRESENT 9
DEPRECIATION STUDY DATA - 2015 RETIREMENTS 10
NET SALVAGE ACTIVITY THROUGH 2018 11
BLANKET WORK ORDERS 11
CONCLUSION 14

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

Description	Page No.
I. INTRODUCTION	2
II. SUMMARY OF RESULTS OF OPERATIONS	4
III. MAJOR COMPONENTS CONTRIBUTING TO THE DEFICIENCY	5
IV. OVERVIEW OF NATURAL GAS OPERATIONS	7
V. JURISDICTIONAL COST RESPONSIBILITY AND ALLOCATIONS	8
VI. OPERATING EXPENSES	11
Adjustment No. 3 – Labor and Labor Loading Annualization	11
Adjustment No. 4 – Call Center and Customer Support Allocation and Annualization	17
Adjustment No. 5 – Cost of Service Analysis	18
Adjustment No. 6 – Employee Vehicle Compensation	18
Adjustment No. 7 – Uncollectible Expense Annualization	19
Adjustment No. 8 – Not Used	19
Adjustment No. 9 – Self-Insured Retention	19
Adjustment No. 10 – AGA Dues	21
Adjustment No. 11 – Paiute Pipeline/SGTC Allocation Annualization	21
Adjustment No. 12 – Rate Case Expense	22
Adjustment No. 13 – Depreciation and Amortization Expense	22
Adjustment No. 14 – Taxes Other Than Income	25
Adjustment No. 15 – Interest on Customer Deposits	25
Adjustment No. 16 – Regulatory Amortizations	26
VII. EMPLOYEE COMPENSATION EXPENSE	28
VIII. RATE BASE	36
Adjustment No. 17 – PTY Plant	38
Adjustment No. 18 – LNG Storage Facility	39
Adjustment No. 19 – Deferred Tax Adjustments	41
IX. FAIR VALUE RATE OF RETURN REQUESTED BY THE COMPANY FOR THIS GRC AND FOR INCREMENTAL INVESTMENTS BETWEEN GRCS	42

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

---

[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).

---

[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

---

[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

[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

Table of Contents
of
Prepared Direct Testimony
of
THEODORE K. WOOD

Description	Page No.
I. INTRODUCTION	1
II. SOUTHWEST GAS' FAIR VALUE RATE OF RETURN (FVROR)	3
III. SOUTHWEST GAS' FINANCIAL PROFILE	5
A. Credit Ratings	5
B. Holding Company Reorganization	8
C. Tax Reform	9
D. Delivery Charge Adjustment (DCA)	12
E. Infrastructure Replacement Programs	13
F. Capital Attraction	17
IV. RECOMMENDED CAPITAL STRUCTURE	19
V. EMBEDDED COST OF LONG-TERM DEBT	21
VI. INCREMENTAL FVROR AS APPROPRIATE RATE OF RETURN FOR CAPITAL TRACKER PROGRAMS	25

Appendix A – Summary of Qualifications of Theodore K. Wood

Exhibit No.__(TKW-1)

Exhibit No.__(TKW-2)

Exhibit No.__(TKW-3)

Exhibit No.__(TKW-4)

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

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

---

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

---

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.

---

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. Infrastructure Replacement Programs

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. Capital Attraction

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

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

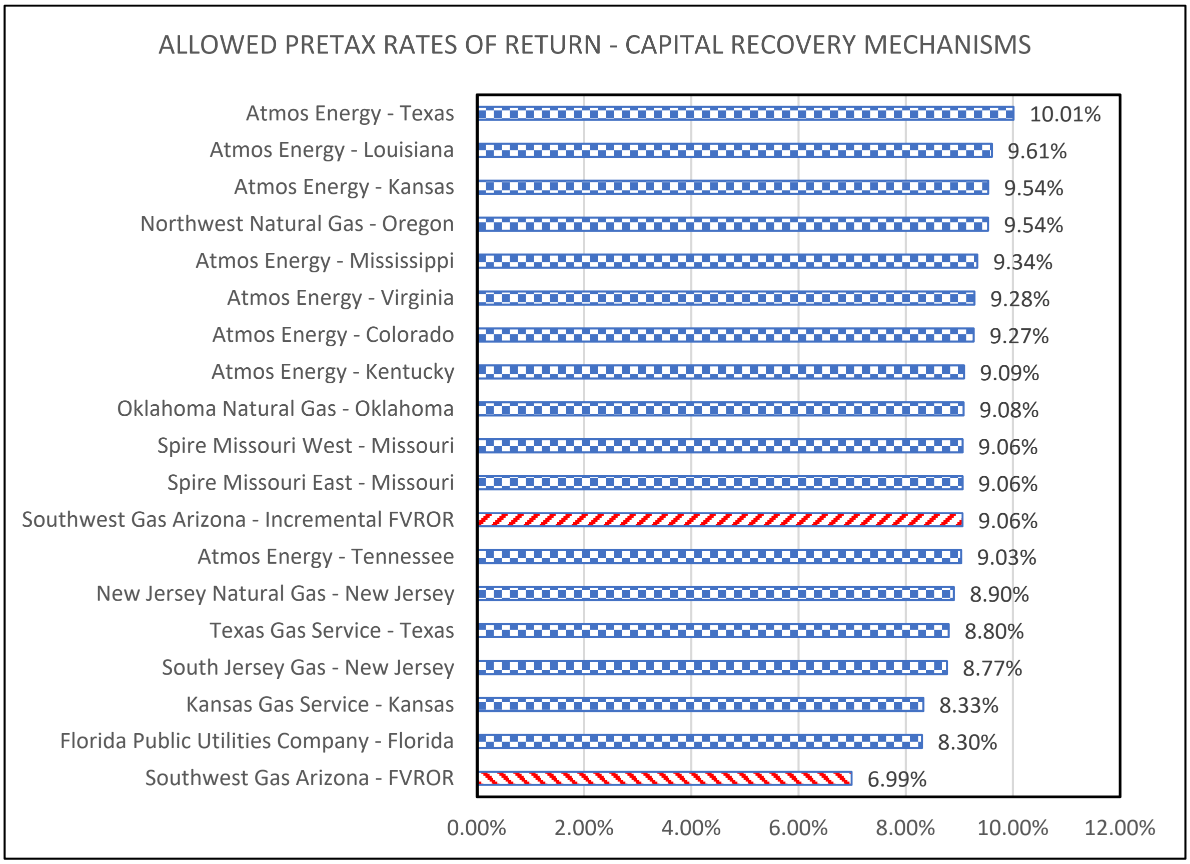
Q. 46 Please confirm the appropriateness of the incremental FVROR by demonstrating that it results in an equivalent revenue requirement as compared to a general rate case.

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

Southwest Gas Corporation

Update to credit analysis

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.

Contacts

Nana Hamilton +1.212.553.9440
AVP-Analyst
nana.hamilton@moodys.com

Miko McGuire +1.212.553.4802
Associate Analyst
miko.mcguire@moodys.com

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

Jim Hempstead +1.212.553.4318
MD-Utilities
james.hempstead@moodys.com

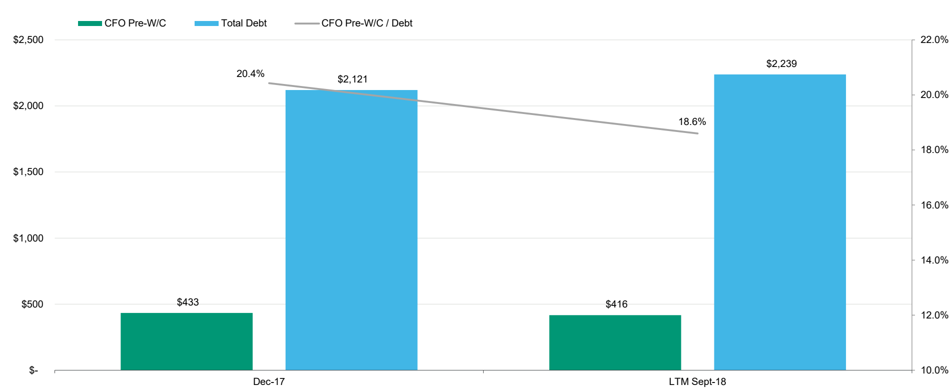
CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

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%

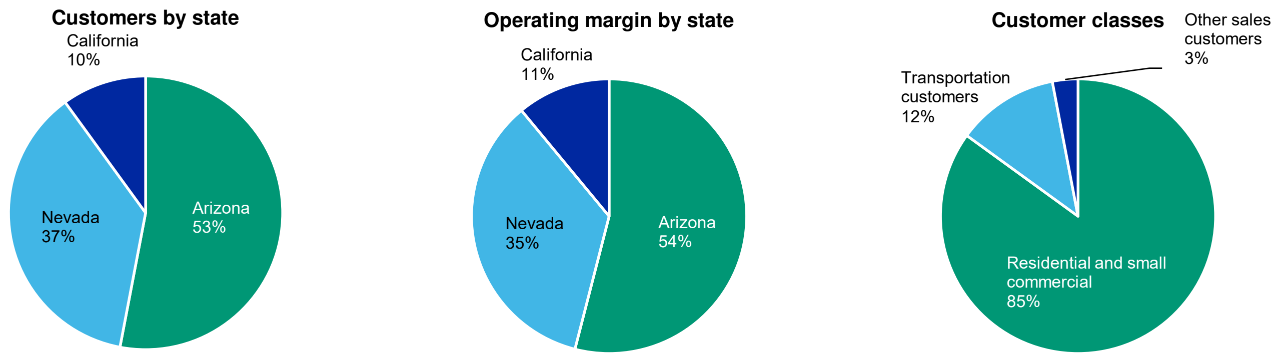
[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

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.

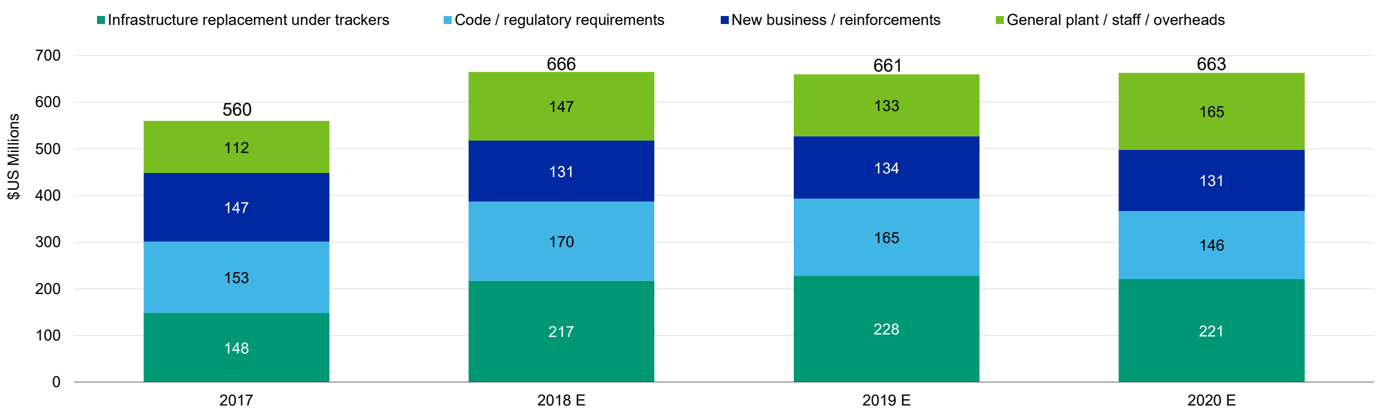
In June 2017, Southwest Gas received approval from the CPUC to extend the current rate case cycle in California by two years. The utility now expects to file its next rate case in California in 2019. The annual post-test year attrition adjustments in California, currently at 2.75%, will continue through 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

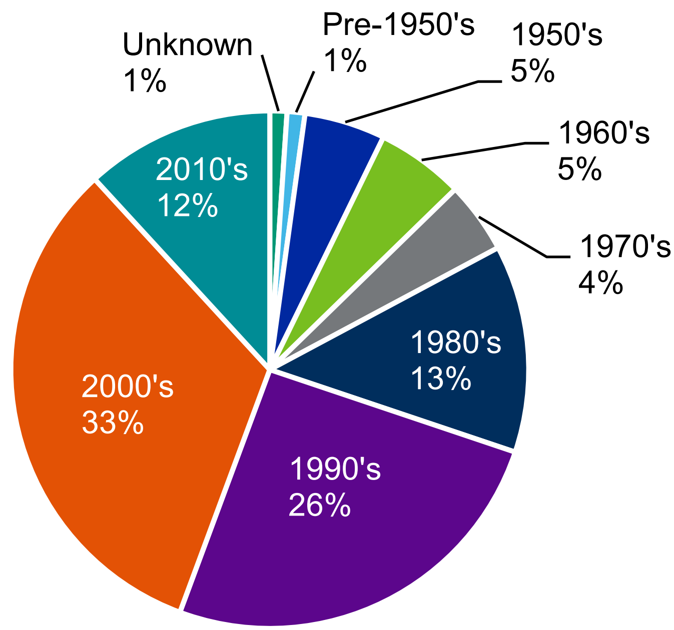
As part of a holding company reorganization effective January 2017, Centuri and Southwest Gas are now separate subsidiaries of a new publicly traded parent holding company, Southwest Gas Holdings. Prior to the reorganization, Centuri was a direct subsidiary of Southwest Gas. We view this change in organizational 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		ONE Gas, Inc		Washington Gas Light Company		Atmos Energy Corporation	
	A3 Stable		A2 Negative		A2 Negative		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
INVESTORS SERVICE

S&P Global
Ratings

RatingsDirect®

Summary:

Southwest Gas Corp.

Primary Credit Analyst:
Obioma Ugboaja, New York 212-438-7406; obioma.ugboaja@spglobal.com

Secondary Contact:
Safina Ali, CFA, New York (1) 212-438-1877; safina.ali@spglobal.com

Research Contributor:
Andrea Dsouza, CRISIL Global Analytical Center, an S&P Global Ratings affiliate, Mumbai

Table Of Contents

Rationale

Outlook

Our Base-Case Scenario

Company Description

Business Risk

Financial Risk

Liquidity

Group Influence

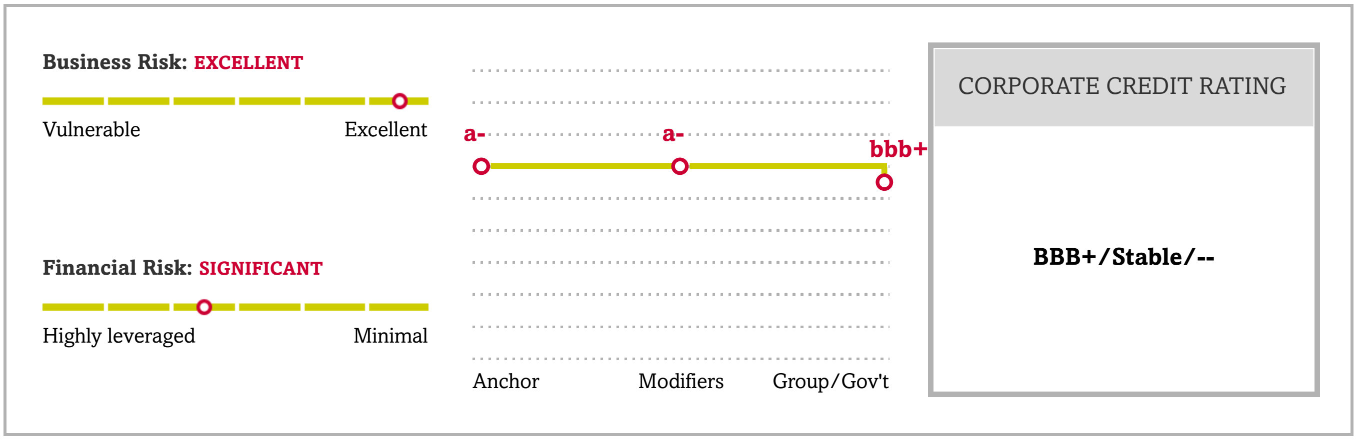
Ratings Score Snapshot

Issue Ratings--Subordination Risk Analysis

Related Criteria

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'.

Contact:

Primary Analyst
Kevin Beicke, CFA
Director
+1 212-908-0618
Fitch Ratings, Inc.
33 Whitehall Street
New York, NY 10004

Secondary Analyst
Jodi Hecht
Director
+1 646-582-4969

Committee Chairperson
Barbara Chapman, CFA
Senior Director
+1 646-582-4886

Media Relations: Elizabeth Fogerty, New York, Tel: +1 (212) 908 0526, Email: elizabeth.fogerty@fitchratings.com

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

or in the particular jurisdiction of the issuer, and a variety of other factors. Users of Fitch's ratings and reports should understand that neither an enhanced factual investigation nor any third-party verification can ensure that all of the information Fitch relies on in connection with a rating or a report will be accurate and complete. Ultimately, the issuer and its advisers are responsible for the accuracy of the information they provide to Fitch and to the market in offering documents and other reports. In issuing its ratings and its reports, Fitch must rely on the work of experts, including independent auditors with respect to financial statements and attorneys with respect to legal and tax matters. Further, ratings and forecasts of financial and other information are inherently forward-looking and embody assumptions and predictions about future events that by their nature cannot be verified as facts. As a result, despite any verification of current facts, ratings and forecasts can be affected by future events or conditions that were not anticipated at the time a rating or forecast was issued or affirmed.

The information in this report is provided "as is" without any representation or warranty of any kind, and Fitch does not represent or warrant that the report or any of its contents will meet any of the requirements of a recipient of the report. A Fitch rating is an opinion as to the creditworthiness of a security. This opinion and reports made by Fitch are based on established criteria and methodologies that Fitch is continuously evaluating and updating. Therefore, ratings and reports are the collective work product of Fitch and no individual, or group of individuals, is solely responsible for a rating or a report. The rating does not address the risk of loss due to risks other than credit risk, unless such risk is specifically mentioned. Fitch is not engaged in the offer or sale of any security. All Fitch reports have shared authorship. Individuals identified in a Fitch report were involved in, but are not solely responsible for, the opinions stated therein. The individuals are named for contact purposes only. A report providing a Fitch rating is neither a prospectus nor a substitute for the information assembled, verified and presented to investors by the issuer and its agents in connection with the sale of the securities. Ratings may be changed or withdrawn at any time for any reason in the sole discretion of Fitch. Fitch does not provide investment advice of any sort. Ratings are not a recommendation to buy, sell, or hold any security. Ratings do not comment on the adequacy of market price, the suitability of any security for a particular investor, or the tax-exempt nature or taxability of payments made in respect to any security. Fitch receives fees from issuers, insurers, guarantors, other obligors, and underwriters for rating securities. Such fees generally vary from US$1,000 to US$750,000 (or the applicable currency equivalent) per issue. In certain cases, Fitch will rate all or a number of issues issued by a particular issuer, or insured or guaranteed by a particular insurer or guarantor, for a single annual fee. Such fees are expected to vary from US$10,000 to US$1,500,000 (or the applicable currency equivalent). The assignment, publication, or dissemination of a rating by Fitch shall not constitute a consent by Fitch to use its name as an expert in connection with any registration statement filed under the United States securities laws, the Financial Services and Markets Act of 2000 of the United Kingdom, or the securities laws of any particular jurisdiction. Due to the relative efficiency of electronic publishing and distribution, Fitch research may be available to electronic subscribers up to three days earlier than to print subscribers.

For Australia, New Zealand, Taiwan and South Korea only: Fitch Australia Pty Ltd holds an Australian financial services license (AFS license no. 337123) which authorizes it to provide credit ratings to wholesale clients only. Credit ratings information published by Fitch is not intended to be used by persons who are retail clients within the meaning of the Corporations Act 2001

Fitch Ratings, Inc. is registered with the U.S. Securities and Exchange Commission as a Nationally Recognized Statistical Rating Organization (the "NRSRO"). While certain of the NRSRO's credit rating subsidiaries are listed on Item 3 of Form NRSRO and as such are authorized to issue credit ratings on behalf of the NRSRO (see https://www.fitchratings.com/site/regulatory), other credit rating subsidiaries are not listed on Form NRSRO (the "non-NRSROs") and therefore credit ratings issued by those subsidiaries are not issued on behalf of the NRSRO. However, non-NRSRO personnel may participate in determining credit ratings issued by or on behalf of the NRSRO.

ENDORSEMENT POLICY - Fitch's approach to ratings endorsement so that ratings produced outside the EU may be used by regulated entities within the EU for regulatory purposes, pursuant to the terms of the EU Regulation with respect to credit rating agencies, can be found on the EU Regulatory Disclosures page. The endorsement status of all International ratings is provided within the entity summary page for each rated entity and in the transaction detail pages for all structured finance transactions on the Fitch website. These disclosures are updated on a daily basis.

SOUTHWEST GAS CORPORATION
PROXY GROUP COMPANIES
THREE-YEAR AVERAGE CAPITALIZATION STATISTICS

PERMANENT CAPITAL STRUCTURE

Line No.	Company (a)	Long-Term Debt (b)	Preferred Equity (c)	Common Equity (d)	Total (e)	Line No.
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 (a)	Total Debt (b)	Preferred Equity (c)	Common Equity (d)	Total (e)	Line No.
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	
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)													**3-Year**
Based on Total Permanent Capital													**Average**
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

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**
Based on Total Permanent Capital													**Average**
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	3-Year Average
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)													
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	
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)													**3-Year Average**
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)

	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	
CAPITALIZATION STATISTICS													
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		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		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

Description — Page No.

I. Introduction 3

II. Summary of Exhibits 4

III. Purpose and Overview of Testimony 5

IV. Regulatory Guidelines and Financial Considerations 11

V. Proxy Group Selection 16

VI. Cost of Equity Estimation 18

VII. Other Considerations 25

Capital Spending and Regulatory Mechanisms 25

Flotation Costs 37

VIII. Capital Market Environment 41

IX. Fair Value Rate Base 49

X. Fair Value Rate Of Return 51

XI. Conclusions and Recommendation 54

Appendix A: Proxy Group Selection 55

Appendix B: Cost Of Common Equity Models 57

A. Constant Growth DCF Model 57

B. CAPM Analysis 64

C. Bond Yield Plus Risk Premium Approach 68

D. Expected Earnings Analysis 72

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.

---

[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

[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.

Section X – Derives the fair value rate of return; and

Section XI – 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]

---

[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

---

[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:

---

[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

---

[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

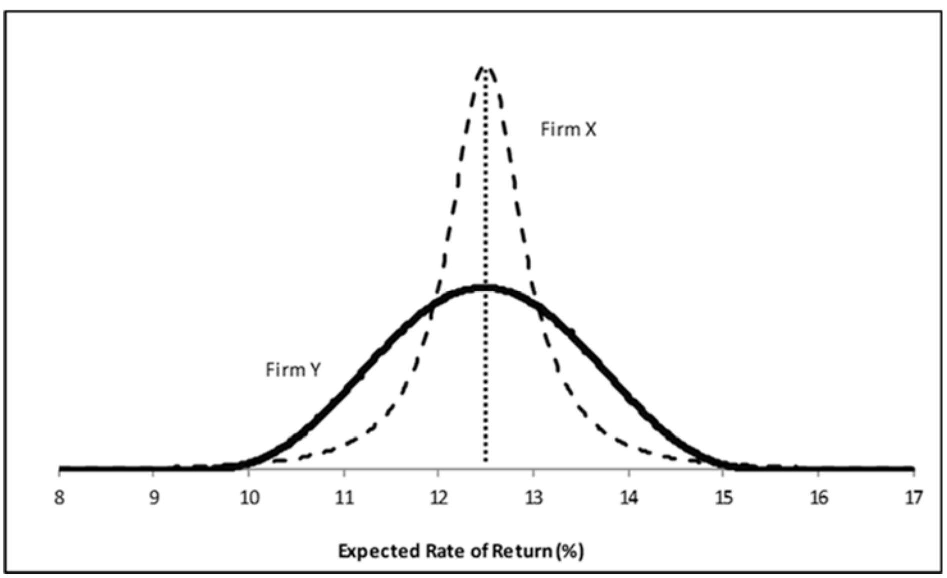
[20] As discussed in Appendix B, the model assumes that earnings, dividends, book value, and the stock price all grow at the same constant rate in perpetuity.

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.

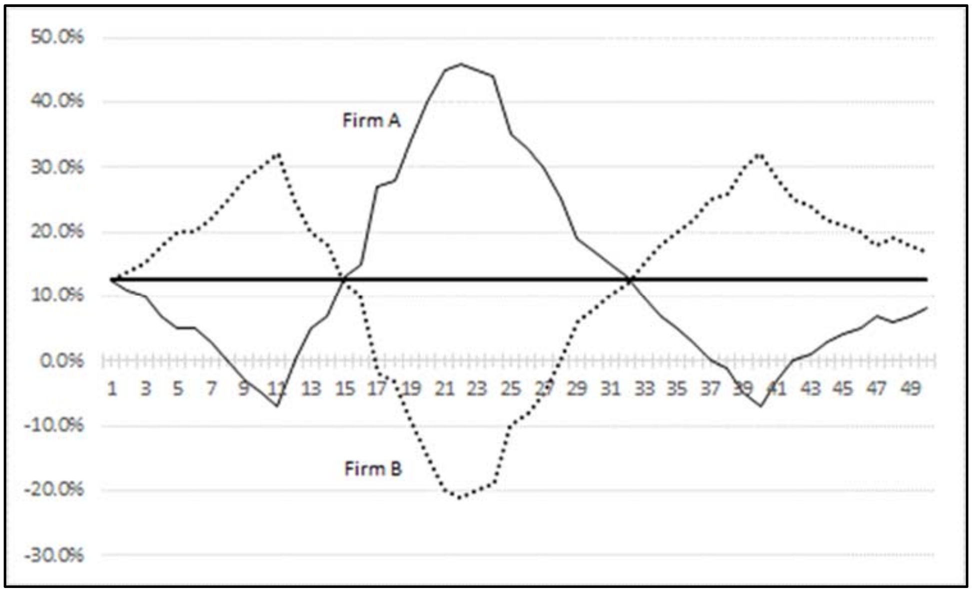
A. 24 Whereas DCF models focus on expected cash flows, Risk Premium-based models such as the CAPM focus on the additional return that investors require for taking on additional risk. In finance, "risk" generally refers to the variation in expected returns, rather than the expected return, itself. Consider 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.

---

[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

---

[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.

---

[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:

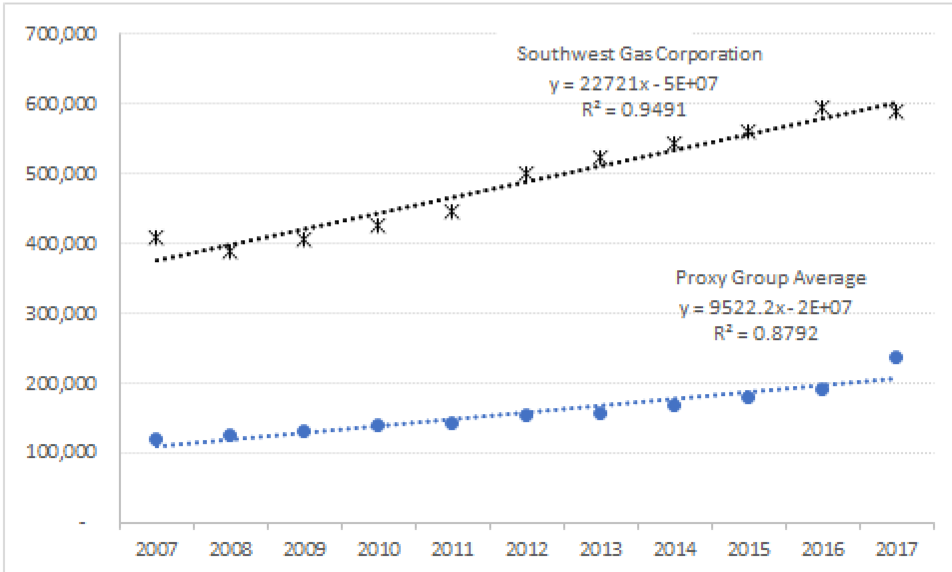
> The SER is a statistical measure that is an estimate of the deviation around a 'best fit' linear trend line. We regress the company's EBITDA, EBITDA margins, or return on capital against time. A key advantage of SER over standard deviation or coefficient of variation is that it doesn't view upwardly 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.

---

[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

---

[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

---

[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.

---

[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.

---

[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.

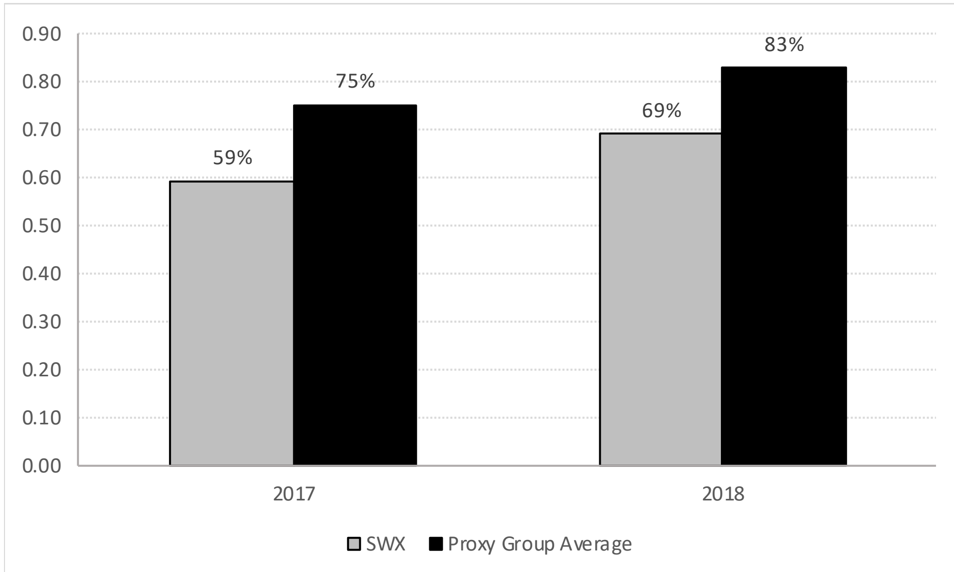
Q. 41 Please further discuss the Company's need to rely on internally generated cash flow and retained earnings to fund capital investments.

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.

---

[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.

---

[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]

---

[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]

---

[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.

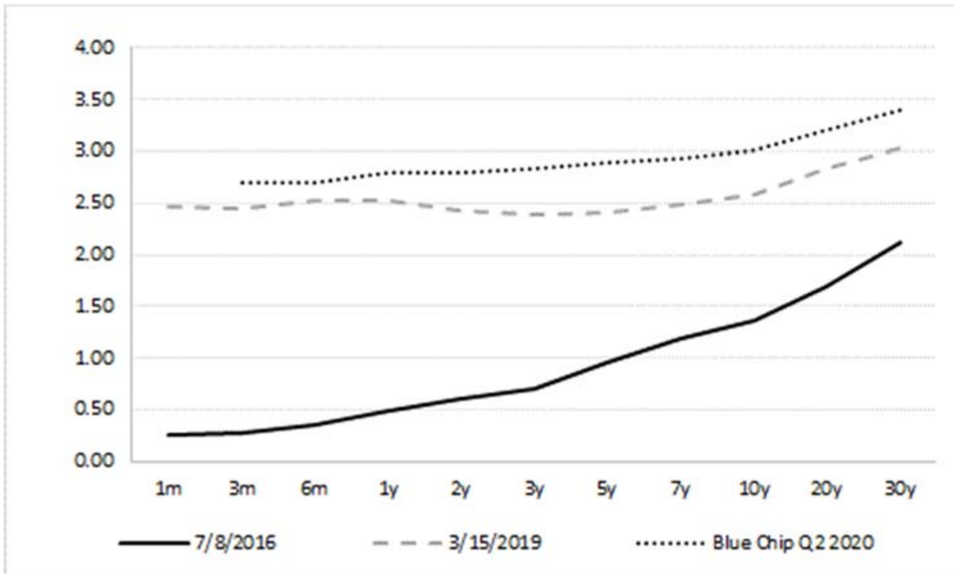
eventually is completed. For example, increasing interest rates may be seen as an indication of expanding macroeconomic growth, in which case we reasonably could expect the growth rate component of the Discounted Cash Flow model to increase. At the same time, sectors that historically have included dividend-paying 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

[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-

---

[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]

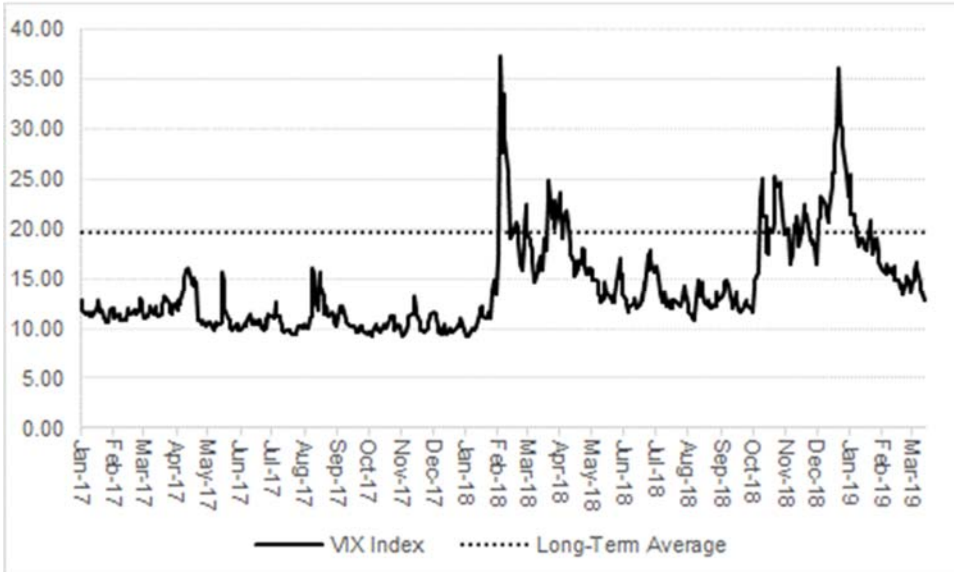


Table 6 (below) further demonstrates the increase in market uncertainty from 2017 to 2019. As that table notes, the standard deviation (that is, the volatility of volatility) in 2018-2019 is about 3.50 times higher than its 2017 level (1.356).

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.

---

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

---

[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.

[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.

---

[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.

---

[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.

[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

---

[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

[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.

---

[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:

$$\left(\frac{m}{b} - 1\right) x\ Growth\ rate\ in\ Common\ Shares \qquad [6]$$

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;

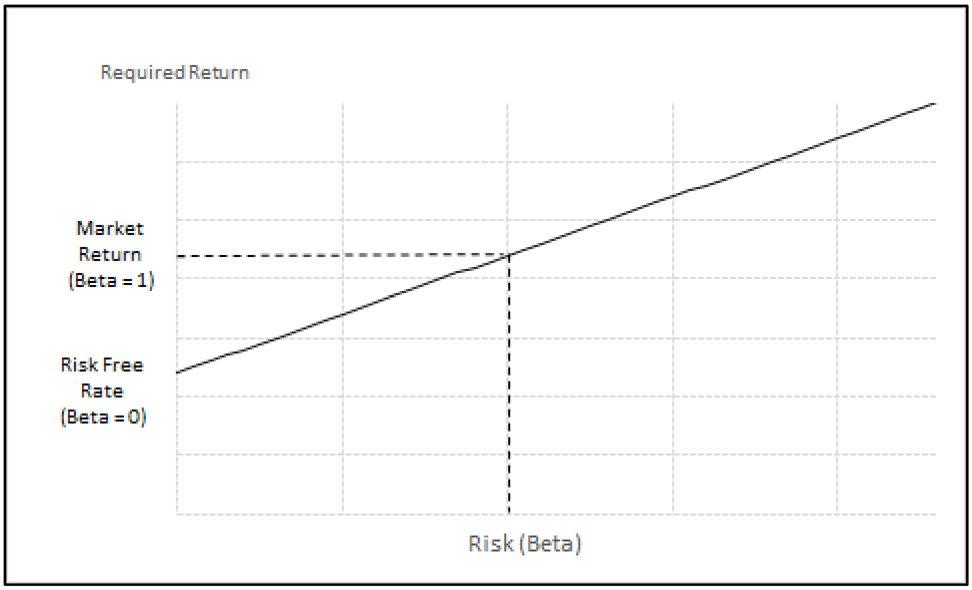
β = the Beta coefficient of that security;

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.

---

[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?

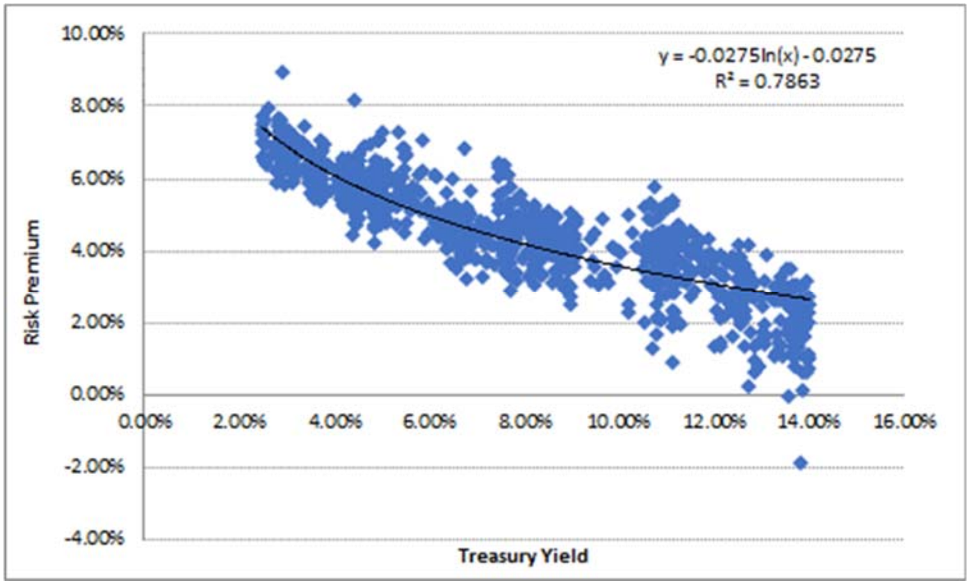
A. 94 The basic method used was regression analysis, in which the observed Equity Risk Premium is the dependent variable, and the average 30-year Treasury yield is the independent variable. Relative to the long-term historical average, the analytical period includes interest rates and authorized ROEs 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).

[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)).

scottmadden
MANAGEMENT CONSULTANTS

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)

scottmadden
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

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

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

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

scottmadden
MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

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

scottmadden
MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

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)

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

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)

scottmadden
MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
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

scottmadden
MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

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)

scottmadden
MANAGEMENT CONSULTANTS

Testimony Listing of:
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:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

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:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

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

scottmadden
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

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

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

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

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]	[17]	[18]
Company	Ticker	Projected Earnings per share 2022-2024	Projected Dividend Declared per share 2022-24	Retention Ratio (B)	Projected Book Value per Share 2022-24	Return on Book Value (R)	B x R	Projected Common Shares Outstanding 2019	Projected Common Shares Outstanding 2022-24	Common Shares Growth Rate	2019 High Price	2019 Low Price	2019 price midpoint	Projected Book Value per Share 2019	Market/ Book Ratio	"S"	"V"	S x V	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%

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	25,750.54	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%

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
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%

		[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	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%

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	14,877.89	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%

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
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

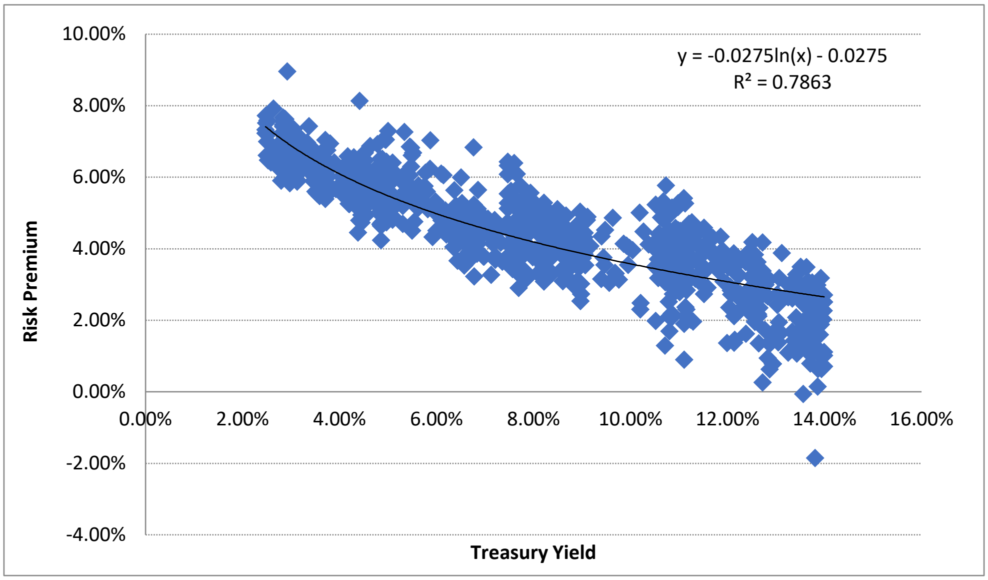
	[1]	[2]	[3]	[4]	[5]	[6]
			Ex-Ante Market Risk Premium		CAPM Result	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg Market DCF Derived	Value Line Market DCF Derived
PROXY GROUP AVERAGE BLOOMBERG BETA COEFFICIENT						
Current 30-Year Treasury [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] Constant	[2] Slope		[3] 30-Year Treasury Yield	[4] Risk Premium	[5] 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